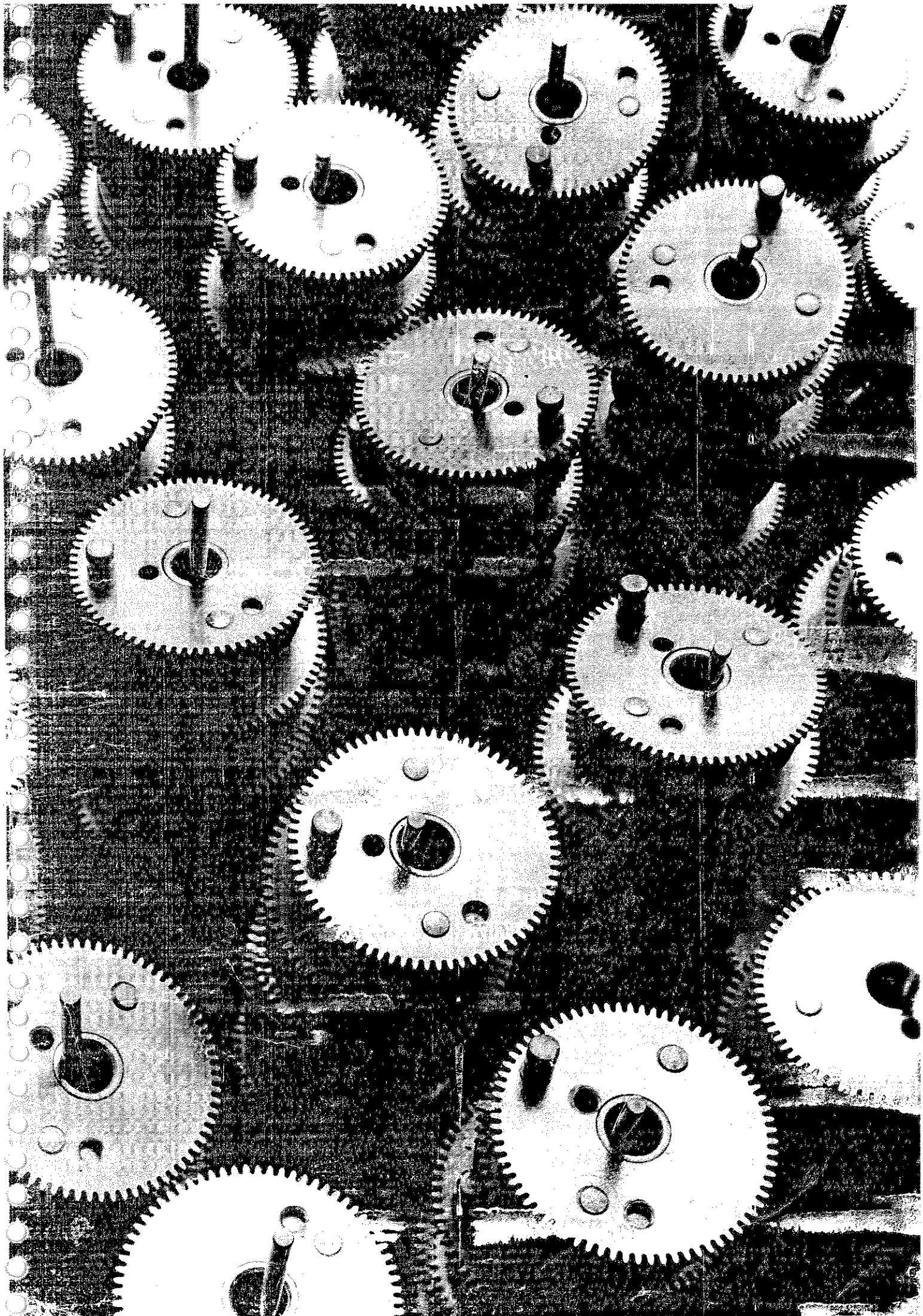












# **PROTECTIVE RELAYS**

## **Application Guide**

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**GEC ALSTHOM MEASUREMENTS LIMITED**

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This book is the result of the co-operation and teamwork of the many specialist engineers employed by GEC ALSTHOM Measurements. The Company would like to acknowledge their assistance in preparing this third edition.

GEC ALSTHOM Measurements also welcomes the opportunity to acknowledge gratefully other help given in preparing this edition.

For providing certain illustrations:

- GEC ALSTHOM Large Machines Limited
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## DEDICATION

Cliff Trickey, C.Eng., MIEE, Marketing Planning Manager of GEC ALSTHOM Measurements, completed the planning and design of this extensively revised edition just prior to his untimely death at the age of 59. This edition is dedicated to his memory.





# Preface

Relaying technology has advanced dramatically since the Second Edition was issued, most notably for the part some form of computer now plays in the various functions. The uses range from the microprocessors employed in the relays themselves, for measurement or control, to testing by computer for development including power system simulation, production testing and even site testing.

Although the book is principally concerned with the applications of relays, particular advances in relay design can significantly affect the way they are used. For example, alternative schemes may be selected within some standard designs, simply at the flick of a switch, sometimes involving a closer integration of protection and control functions. So the relay hardware is becoming even more standardized, to the point where versions of a relay may differ only by the software they contain.

This progress has made it both exciting and desirable to tackle the production of a new, Third Edition of this popular book. Several of the chapters have been totally or substantially rewritten, but the changed scene is perhaps best exemplified by the inclusion of a new chapter on the Application of Microprocessors to Substation Control. This sets out to introduce many of the computation terms which may be unfamiliar to some protection engineers of an older generation.

At what some may regard as the simpler end of the application scale, the scope of the book has been widened to include another new chapter, on the protection of industrial power systems.

The correct application of protective relays requires not only a knowledge of the relay design parameters but

also a good understanding of the behaviour of the power system in which the relay is to be applied. The book attempts to present the practising engineer with sufficient information to assist him in his everyday work, including testing and commissioning, without overstressing the more complex problems. Such problems are, in any case, usually dealt with as a combined effort between the user and the manufacturer, for specific applications.

For the last edition a presentation format was chosen which we believed would be both easy to follow and convenient to use. In response to the many complimentary comments we received, this format has been largely retained for the new edition.

The first part of the book deals with the fundamentals of protective gear practice, basic technology, fault calculations and the circuits and parameters of power system plant, including the transient response and saturation problems that affect the instrument transformers associated with protective relays. The book then goes on to cover the parameters of electromechanical relays, solid state relays and protection signalling and ends with a detailed analysis of the relaying systems associated with power system plant. The final chapter is a guide to good relaying practice, with references to the various types of relays manufactured by GEC ALSTHOM Measurements. The recommended relays and schemes for the main items of power system plant are listed in the various relay application tables.

It is our sincere hope that this book will continue to be used by the many application engineers throughout the world, to serve both as a guide to users and to assist them in training young engineers in relay application

GEC ALSTHOM MEASUREMENTS LIMITED  
St Leonards Works  
Stafford  
England



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# Fundamentals of protection practice

- 1.1 Introduction
- 1.2 Protective gear
- 1.3 Reliability
- 1.4 Availability
- 1.5 System of protection
- 1.6 Reliability
- 1.7 Backup
- 1.8 Protection of a system
- 1.9 Protection of a system by a protection
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- 1.14 Protection of a system
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- 1.16 Protection of a system

## 1.1

The purpose of an electrical power system is to generate and supply electrical energy to consumers. The system should be designed and managed to deliver this energy to the utilization points with both reliability and economy. As these two requirements are largely opposed, it is instructive to look at the reliability of a system and its cost and value to the consumer, which is shown in Figure 1.1

It is important to realize that the system is viable only between the cross-over points *A* and *B*. The diagram illustrates the significance of reliability in system design, and the necessity of achieving sufficient reliability. On the other hand, high reliability should not be pursued as an end in itself, regardless of cost, but should rather be balanced against economy, taking all factors into account.

Security of supply can be bettered by improving plant design, increasing the spare capacity margin and arranging alternative circuits to supply loads. Sub-division of the system into zones, each controlled by switchgear in association with protective gear, provides flexibility during normal operation and ensures a minimum of dislocation following a breakdown.

The greatest threat to the security of a supply system is the short circuit, which imposes a sudden and sometimes violent change on system operation. The large current

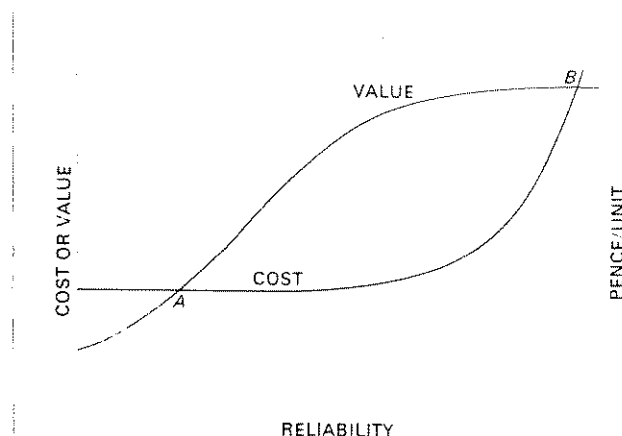


Figure 1.1 Relationship between reliability of supply, its cost and value to the consumer.

tion then flows, accompanied by the localized release of a considerable quantity of energy, can cause fire at the fault location and mechanical damage throughout the system, particularly to machine and transformer windings. Rapid location of the fault by the nearest switchgear will minimize the damage and disruption caused to the system.

A power system represents a very large capital investment. To maximize the return on this outlay, the system must be treated as much as possible. For this reason it is necessary not only to provide a supply of energy which is attractive to prospective users by operating the system within the range  $AB$  (Figure 1.1), but also to keep the system in full operation as far as possible continuously, so that it may give the best service to the consumer, and earn the most revenue for the supply authority. Absolute freedom from failure of the plant and system network cannot be guaranteed. The risk of a fault occurring, however slight for each item, is multiplied by the number of such items which are closely associated in an extensive system, as any fault produces repercussions throughout the network. When the system is large, the chance of a fault occurring and the disturbance that a fault would bring are both so great that without equipment to remove faults the system will become, in practical terms, inoperable. The object of the system will be defeated if adequate provision for fault clearance is not made. Nor is the installation of switchgear alone sufficient; discriminative protective gear, designed according to the characteristics and requirements of the power system, must be provided to control the switchgear. A system is not properly designed and managed if it is not adequately protected. This is the measure of the importance of protective systems in modern practice and of the responsibility vested in the protection engineer.

## 1.2

This is a collective term which covers all the equipment used for detecting, locating and initiating the removal of a fault from the power system. Relays are extensively used for major protective functions, but the term also covers direct-acting a.c. trips and fuses.

In addition to relays the term includes all accessories such as current and voltage transformers, shunts, d.c. and a.c. wiring and any other devices relating to the protective relays.

In general, the main switchgear, although fundamentally protective in its function, is excluded from the term 'protective gear', as are also common services, such as the station battery and any other equipment required to secure operation of the circuit breaker.

In order to fulfil the requirements of discriminative protection with the optimum speed for the many different configurations, operating conditions and construction features of power systems, it has been necessary to develop many types of relay which respond to various functions of the power system quantities. For example, observation simply of the magnitude of the fault current suffices in some cases but measurement of power or impedance may be necessary in others. Relays frequently measure complex functions of the system quantities, which are only readily expressible by mathematical or graphical means.

In many cases it is not feasible to protect against all hazards with any one relay. Use is then made of a combination of different types of relay which individually protect against different risks. Each individual protective arrangement is known as a 'protection system', while the whole co-ordinated combination of relays is called a 'protection scheme'.

## 1.3

The need for a high degree of reliability is discussed in Section 1.1. Incorrect operation can be attributed to one of

the following classifications:

- a. Incorrect design.
- b. Incorrect installation.
- c. Deterioration.

### 1.3.1

#### Design

This is of the highest importance. The nature of the power system condition which is being guarded against must be thoroughly understood in order to make an adequate protection design. Comprehensive testing is just as important, and this testing should cover all aspects of the protection, as well as reproducing operational and environmental conditions as closely as possible. For many protective systems, it is necessary to test the complete assembly of relays, current transformers and other ancillary items, and the tests must simulate fault conditions realistically. This subject will be dealt with at greater length in Chapter 23.

### 1.3.2

#### Installation

The need for correct installation of protective equipment is obvious, but the complexity of the interconnections of many systems and their relationship to the remainder of the station may make difficult the checking of such correctness. Testing is therefore necessary; since it will be difficult to reproduce all fault conditions correctly, these tests must be directed to proving the installation. This is the function of site testing, which should be limited to such simple and direct tests as will prove the correctness of the connections and freedom from damage of the equipment. No attempt should be made to 'type test' the equipment or to establish complex aspects of its technical performance; see Chapter 23.

### 1.3.3

#### Deterioration in service

After a piece of equipment has been installed in perfect condition, deterioration may take place which, in time, could interfere with correct functioning. For example, contacts may become rough or burnt owing to frequent operation, or tarnished owing to atmospheric contamination; coils and other circuits may be open-circuited, auxiliary components may fail, and mechanical parts may become clogged with dirt or corroded to an extent that may interfere with movement.

One of the particular difficulties of protective relays is that the time between operations may be measured in years, during which period defects may have developed unnoticed until revealed by the failure of the protection to respond to a power system fault. For this reason, relays should be given simple basic tests at suitable intervals in order to check that their ability to operate has not deteriorated.

Testing should be carried out without disturbing permanent connections. This can be achieved by the provision of test blocks or switches. Draw-out relays inherently provide this facility; a test plug can be inserted between the relay and case contacts giving access to all relay input circuits for injection. When temporary disconnection of panel wiring is necessary, mistakes in correct restoration of connections can be avoided by using identity tags on leads and terminals, clip-on leads for injection supplies, and easily visible double-ended clip-on leads where 'jumper connections' are required.

The quality of testing personnel is an essential feature when assessing reliability and considering means for improvement. Staff must be technically competent and adequately trained, as well as self-disciplined to proceed in a deliberate manner, in which each step taken and quantity measured is checked before final acceptance.

Important circuits which are specially vulnerable can be

provided with continuous electrical supervision; such arrangements are commonly applied to circuit breaker trip circuits and to pilot circuits.

#### 1.3.4

##### Protection performance

The performance of the protection applied to large power systems is frequently assessed numerically. For this purpose each system fault is classed as an incident and those which are cleared by the tripping of the correct circuit breakers and only those, are classed as 'correct'. The percentage of correct clearances can then be determined.

This principle of assessment gives an accurate evaluation of the protection of the system as a whole, but it is severe in its judgement of relay performance, in that many relays are called into operation for each system fault, and all must behave correctly for a correct clearance to be recorded.

On this basis, a performance of 94% is obtainable by standard techniques.

Complete reliability is unlikely ever to be achieved by further improvements in construction. A very big step, however, can be taken by providing duplication of equipment or 'redundancy'. Two complete sets of equipment are provided, and arranged so that either by itself can carry out the required function. If the risk of an equipment failing is  $x$ /unit, the resultant risk, allowing for redundancy, is  $x^2$ . Where  $x$  is small the resultant risk ( $x^2$ ) may be negligible.

It has long been the practice to apply duplicate protective systems to busbars, both being required to operate to complete a tripping operation, that is, a 'two-out-of-two' arrangement. In other cases, important circuits have been provided with duplicate main protection schemes, either being able to trip independently, that is, a 'one-out-of-two' arrangement. The former arrangement guards against unwanted operation, the latter against failure to operate.

These two features can be obtained together by adopting a 'two-out-of-three' arrangement in which three basic systems are used and are interconnected so that the operation of any two will complete the tripping function. Such schemes have already been used to a limited extent and application of the principle will undoubtedly increase. Probability theory suggests that if a power network were protected throughout on this basis, a protection performance of 99.98% should be attainable.

This performance figure requires that the separate protection systems be completely independent; any common factors, such as common current transformers or tripping batteries, will reduce the overall performance.

#### 1.4

Protection is arranged in zones, which should cover the power system completely, leaving no part unprotected. When a fault occurs the protection is required to select and trip only the nearest circuit breakers. This property of selective tripping is also called 'discrimination' and is achieved by two general methods:

##### a. Time graded systems.

Protective systems in successive zones are arranged to operate in times which are graded through the sequence of equipments so that upon the occurrence of a fault, although a number of protective equipments respond, only those relevant to the faulty zone complete the tripping function. The others make incomplete operations and then reset.

##### b. Unit systems.

It is possible to design protective systems which respond only to fault conditions lying within a clearly defined zone. This 'unit protection' or 'restricted protection' can be applied throughout a power system and, since it does not

involve time grading, can be relatively fast in operation.

Unit protection is usually achieved by means of a comparison of quantities at the boundaries of the zone. Certain protective systems derive their 'restricted' property from the configuration of the power system and may also be classed as unit protection.

Whichever method is used, it must be kept in mind that selectivity is not merely a matter of relay design. It also depends on the correct co-ordination of current transformers and relays with a suitable choice of relay settings, taking into account the possible range of such variables as fault currents, maximum load current, system impedances and other related factors, where appropriate.

#### 1.5

Ideally, the zones of protection mentioned in Section 1.4 should overlap across the circuit breaker as shown in Figure 1.2, the circuit breaker being included in both zones.

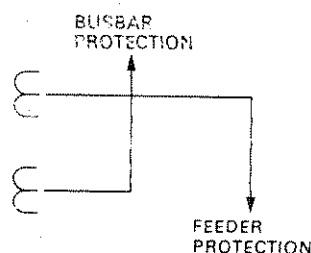


Figure 1.2 Location of current transformers on both sides of the circuit breaker.

For practical physical reasons, this ideal is not always achieved, accommodation for current transformers being in some cases available only on one side of the circuit breakers, as in Figure 1.3. This leaves a section between the current transformers and the circuit breaker *A* within which a fault is not cleared by the operation of the protection that responds. In Figure 1.3 a fault at *F* would cause the busbar protection to operate and open the circuit breaker but the fault would continue to be fed through the feeder.

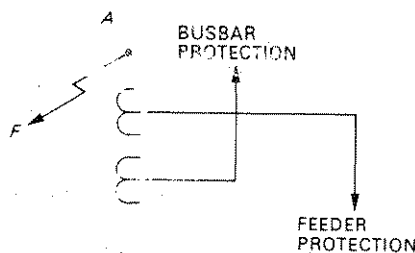


Figure 1.3 Location of current transformers on circuit side of the circuit breaker.

The feeder protection, if of the unit type, would not operate, since the fault is outside its zone. This problem is dealt with by some form of zone extension, to operate when opening the circuit breaker does not fully interrupt the flow of fault current. A time delay is incurred in fault clearance, although by restricting this operation to occasions when the busbar protection is operated the time delay can be reduced.

The point of connection of the protection with the power system usually defines the zone and corresponds to the location of the current transformers. The protection may be

of the unit type, in which case the boundary will be a clearly defined and closed loop. Figure 1.4 illustrates a typical arrangement of overlapping zones.

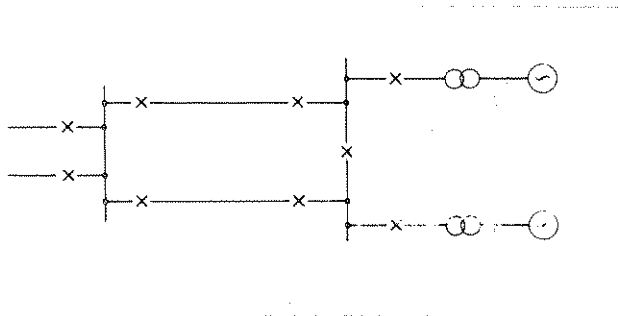


Figure 1.4 Overlapping zones of protection systems

Alternatively, the zone may be unrestricted; the start will be defined but the extent will depend on measurement of the system quantities and will therefore be subject to variation, owing to changes in system conditions and measurement errors.

## 1.6

This term, applied to protection as distinct from power networks, refers to the ability of the system to remain inert to all load conditions and faults external to the relevant zone. It is essentially a term which is applicable to unit systems; the term 'discrimination' is the equivalent expression applicable to non-unit systems.

## 1.7

The function of automatic protection is to isolate faults from the power system in a very much shorter time than could be achieved manually, even with a great deal of personal supervision. The object is to safeguard continuity of supply by removing each disturbance before it leads to widespread loss of synchronism, which would necessitate the shutting down of plant.

Loading the system produces phase displacements between the voltages at different points and therefore increases the probability that synchronism will be lost when the system is disturbed by a fault. The shorter the time a fault is allowed to remain in the system, the greater can be the loading of the system. Figure 1.5 shows typical relations between system loading and fault clearance times for various types of fault. It will be noted that phase faults have a more marked effect on the stability of the system than does a simple earth fault and therefore require faster clearance.

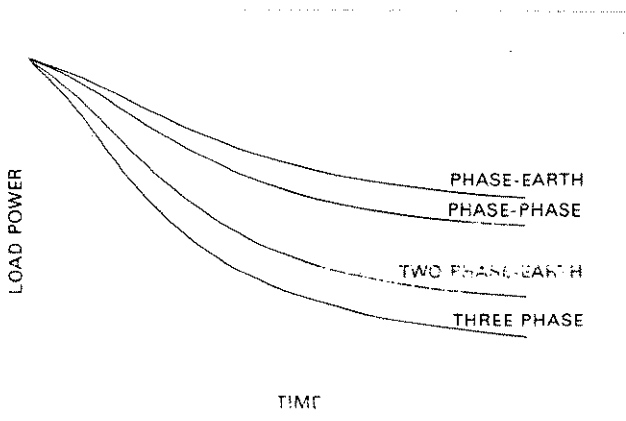


Figure 1.5 Typical values of power that can be transmitted as a function of fault clearance time.

It is not enough to maintain stability; unnecessary consequential damage must also be avoided. The destructive power of a fault arc carrying a high current is very great, it can burn through copper conductors or weld together core laminations in a transformer or machine in a very short time. Even away from the fault arc itself, heavy fault currents can cause damage to plant if they continue for more than a few seconds.

It will be seen that protective gear must operate as quickly as possible; speed, however, must be weighed against economy. For this reason, distribution circuits for which the requirements for fast operation are not very severe are usually protected by time-graded systems, but generating plant and EHV systems require protective gear of the highest attainable speed; the only limiting factor will be the necessity for correct operation.

## 1.8

Sensitivity is a term frequently used when referring to the minimum operating current of a complete protective system. A protective system is said to be sensitive if the primary operating current is low.

When the term is applied to an individual relay, it does not refer to a current or voltage setting but to the volt-ampere consumption at the minimum operating current.

A given type of relay element can usually be wound for a wide range of setting currents; the coil will have an impedance which is inversely proportional to the square of the setting current value, so that the volt-ampere product at any setting is constant. This is the true measure of the input requirements of the relay, and so also of the sensitivity. Relay power factor has some significance in the matter of transient performance and this is discussed in Chapter 5. For d.c. relays the VA input also represents power consumption, and the burden is therefore frequently quoted in watts.

## 1.9

The reliability of a power system has been discussed in earlier sections. Many factors may cause protection failure and there is always some possibility of a circuit breaker failure. For this reason, it is usual to supplement primary protection with other systems to 'back-up' the operation of the main system and to minimize the possibility of failure to clear a fault from the system.

Back-up protection may be obtained automatically as an inherent feature of the main protection scheme, or separately by means of additional equipment. Time graded schemes such as overcurrent or distance protection schemes are examples of those providing inherent back-up protection; the faulty section is normally isolated discriminatively by the time grading, but if the appropriate relay fails or the circuit breaker fails to trip, the next relay in the grading sequence will complete its operation and trip the associated circuit breaker, thereby interrupting the fault circuit one section further back. In this way complete back-up cover is obtained; one more section is isolated than is desirable but this is inevitable in the event of the failure of a circuit breaker.

Where the system interconnection is more complex, the above operation will be repeated so that all parallel infeeds are tripped.

If the power system is protected mainly by unit schemes, automatic back-up protection is not obtained, and it is then normal to supplement the main protection with time graded overcurrent protection, which will provide local back-up cover if the main protective relays have failed, and will trip further back in the event of circuit breaker failure.



Such back-up protection is inherently slower than the main protection and, depending on the power system configuration, may be less discriminative. For the most important circuits the performance may not be good enough, even as a back-up protection, or, in some cases, not even possible, owing to the effect of multiple infeeds. In these cases duplicate high speed protective systems may be installed. These provide excellent mutual back-up cover against failure of the protective equipment, but either no remote back-up protection against circuit breaker failure or, at best, time delayed cover.

Breaker fail protection can be obtained by checking that fault current ceases within a brief time interval from the operation of the main protection. If this does not occur, all other connections to the busbar section are interrupted, the condition being necessarily treated as a busbar fault. This provides the required back-up protection with the minimum of time delay, and confines the tripping operation to the one station, as compared with the alternative of tripping the remote ends of all the relevant circuits.

The extent and type of back-up protection which is applied will naturally be related to the failure risks and relative economic importance of the system. For distribution systems where fault clearance times are not critical, time delayed remote back-up protection is adequate but for EHV systems, where system stability is at risk unless a fault is cleared quickly, local back-up, as described above, should be chosen.

Ideal back-up protection would be completely independent of the main protection. Current transformers, voltage transformers, auxiliary tripping relays, trip coils and d.c. supplies would be duplicated. This ideal is rarely attained in practice. The following compromises are typical;

a. Separate current transformers (cores and secondary windings only) are used for each protective system, as this involves little extra cost or accommodation compared with the use of common current transformers which would have to be larger because of the combined burden.

b. Common voltage transformers are used because duplication would involve a considerable increase in cost, because of the voltage transformers themselves, and also because of the increased accommodation which would have to be provided. Since security of the VT output is vital, it is desirable that the supply to each protection should be separately fused and also continuously supervised by a relay which will give an alarm on failure of the supply and, where appropriate, prevent an unwanted operation of the protection.

c. Trip supplies to the two protections should be separately fused. Duplication of tripping batteries and of tripping coils on circuit breakers is sometimes provided. Trip circuits should be continuously supervised.

d. It is desirable that the main and back-up protections (or duplicate main protections) should operate on different principles, so that unusual events that may cause failure of the one will be less likely to affect the other.

## 1.10

### DEFINITIONS AND TERMINOLOGY

#### *All-or-nothing relay*

An electrical relay which is intended to be energized by a quantity whose value is either higher than that at which it picks up or lower than that at which it drops out.

#### *Auxiliary relay*

An all-or-nothing relay energized via the contacts of another relay, for example a measuring relay, for the purpose of providing higher rated contacts or introducing a time delay.

#### *Back-up protection*

A protective system intended to supplement the main protection in case the latter should be ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zones of the main protection.

#### *Biased relay*

A relay in which the characteristics are modified by the introduction of some quantity other than the actuating quantity, and which is usually in opposition to the actuating quantity.

#### *Burden*

The loading imposed by the circuits of the relay on the energizing power source or sources, expressed as the product of voltage and current (volt-amperes, or watts if d.c.) for a given condition, which may be either at 'setting' or at rated current or voltage.

The rated output of measuring transformers, expressed in VA, is always at rated current or voltage and it is important, in assessing the burden imposed by a relay, to ensure that the value of burden at rated current is used.

#### *Characteristic angle*

The angle between the vectors representing two of the energizing quantities applied to a relay and used for the declaration of the performance of the relay.

#### *Characteristic curve*

The curve showing the operating value of the characteristic quantity corresponding to various values or combinations of the energizing quantities.

#### *Characteristic quantity*

A quantity, the value of which characterizes the operation of the relay, for example, current for an overcurrent relay, voltage for a voltage relay, phase angle for a directional relay, time for an independent time delay relay, impedance for an impedance relay.

#### *Characteristic impedance ratio (C.I.R.)*

The maximum value of the System Impedance Ratio up to which the relay performance remains within the prescribed limits of accuracy.

#### *Check protective system*

An auxiliary protective system intended to prevent tripping due to inadvertent operation of the main protective system.

#### *Conjunctive test*

A test on a protective system including all relevant components and ancillary equipment appropriately interconnected. The test may be parametric or specific.

##### *a. Parametric conjunctive test.*

A test to ascertain the range of values that may be assigned to each parameter when considered in combination with other parameters, while still complying with the relevant performance requirements.

##### *b. Specific conjunctive test.*

A test to prove the performance for a particular application, for which definite values are assigned to each of the parameters.

#### *Dependent time measuring relay*

A measuring relay for which times depend, in a specified manner, on the value of the characteristic quantity.

### **Discrimination**

The ability of a protective system to distinguish between power system conditions for which it is intended to operate and those for which it is not intended to operate.

### **Drop-out**

A relay drops out when it moves from the energized position to the un-energized position.

### **Drop-out/pick-up ratio**

The ratio of the limiting values of the characteristic quantity at which the relay resets and operates. This value is sometimes called the differential of the relay.

### **Earth fault protective system**

A protective system which is designed to respond only to faults to earth.

### **Earthing transformer**

A three-phase transformer intended essentially to provide a neutral point to a power system for the purpose of earthing.

### **Effective range**

The range of values of the characteristic quantity or quantities, or of the energizing quantities to which the relay will respond and satisfy the requirements concerning it, in particular those concerning precision.

### **Effective setting**

The 'setting' of a protective system including the effects of current transformers. The effective setting can be expressed in terms of primary current or secondary current from the current transformers and is so designated as appropriate.

### **Electrical relay**

A device designed to produce sudden predetermined changes in one or more electrical circuits after the appearance of certain conditions in the electrical circuit or circuits controlling it.

NOTE: The term 'relay' includes all the ancillary equipment calibrated with the device.

### **Electromechanical relay**

An electrical relay in which the designed response is developed by the relative movement of mechanical elements under the action of a current in the input circuit.

### **Energizing quantity**

The electrical quantity, either current or voltage, which alone or in combination with other energizing quantities, must be applied to the relay to cause it to function.

### **Independent time measuring relay**

A measuring relay, the specified time for which can be considered as being independent, within specified limits, of the value of the characteristic quantity.

### **Instantaneous relay**

A relay which operates and resets with no intentional time delay.

NOTE: All relays require some time to operate; it is possible, within the above definition, to discuss the operating time characteristics of an instantaneous relay.

### **Inverse time delay relay**

A dependent time delay relay having an operating time which is an inverse function of the electrical characteristic quantity.

### **Inverse time relay with definite minimum time (I.D.M.T.)**

An inverse time relay having an operating time that tends towards a minimum value with increasing values of the electrical characteristic quantity.

### **Knee-point e.m.f.**

That sinusoidal e.m.f. applied to the secondary terminals of a current transformer, which, when increased by 10% causes the exciting current to increase by 50%.

### **Main protection**

The protective system which is normally expected to operate in response to a fault in the protected zone.

### **Measuring relay**

An electrical relay intended to switch when its characteristic quantity, under specified conditions and with a specified accuracy attains its operating value.

### **Notching relay**

A relay which switches in response to a specific number of applied impulses.

### **Operating time**

With a relay de-energized and in its initial condition, the time which elapses between the application of a characteristic quantity and the instant when the relay operates.

### **Operating time characteristic**

The curve depicting the relationship between different values of the characteristic quantity applied to a relay and the corresponding values of operating time.

### **Operating value**

The limiting value of the characteristic quantity at which the relay actually operates.

### **Overshoot time**

The overshoot time is the difference between the operating time of the relay at a specified value of the input energizing quantity and the maximum duration of the value of input energizing quantity which, when suddenly reduced to a specific value below the operating level, is insufficient to cause operation.

### **Pick-up**

A relay is said to 'pick-up' when it changes from the un-energized position to the energized position.

### **Pilot channel**

A means of interconnection between relaying points for the purpose of protection.

### **Protected zone**

The portion of a power system protected by a given protective system or a part of that protective system.

### **Protective gear**

The apparatus, including protective relays, transformers and ancillary equipment, for use in a protective system.

### **Protective relay**

A relay designed to initiate disconnection of a part of an electrical installation or to operate a warning signal, in the case of a fault or other abnormal condition in the installation.

A protective relay may include more than one unit electrical relay and accessories.

### **Protective scheme**

The co-ordinated arrangements for the protection of one or more elements of a power system.

A protective scheme may comprise several protective systems.

### **Protective system**

A combination of protective gear designed to secure, under predetermined conditions, usually abnormal, the disconnection of an element of a power system, or to give an alarm signal, or both.

### **Rating**

The nominal value of an energizing quantity which appears in the designation of a relay. The nominal value usually corresponds to the CT and VT secondary ratings.

### **Resetting value**

The limiting value of the characteristic quantity at which the relay returns to its initial position.

### **Residual current**

The algebraic sum, in a multi-phase system, of all the line currents.

### **Residual voltage**

The algebraic sum, in a multi-phase system, of all the line-to-earth voltages.

### **Setting**

The limiting value of a 'characteristic' or 'energizing' quantity at which the relay is designed to operate under specified conditions.

Such values are usually marked on the relay and may be expressed as direct values, percentages of rated values, or multiples.

### **Stability**

The quality whereby a protective system remains inoperative under all conditions other than those for which it is specifically designed to operate.

### **Stability limits**

The r.m.s. value of the symmetrical component of the through fault current up to which the protective system remains stable.

### **Starting relay**

A unit relay which responds to abnormal conditions and initiates the operation of other elements of the protective system.

### **Static relay**

An electrical relay in which the designed response is developed by electronic, magnetic, optical or other components without mechanical motion.

It should be noted though that few static relays have a fully static output stage, to trip directly from thyristors for

example. By far the majority of static relays have attracted armature output elements to provide metal-to-metal contacts, which remain the preferred output medium in general.

### **System impedance ratio (S.I.R.)**

The ratio of the power system source impedance to the impedance of the protected zone.

### **Through fault current**

The current flowing through a protected zone to a fault beyond that zone.

### **Time delay**

A delay intentionally introduced into the operation of a relay system.

### **Time delay relay**

A relay having an intentional delaying device.

### **Unit electrical relay**

A single relay which can be used alone or in combinations with others.

### **Unit protection**

A protection system which is designed to operate only for abnormal conditions within a clearly defined zone of the power system.

### **Unrestricted protection**

A protection system which has no clearly defined zone of operation and which achieves selective operation only by time grading.

The above is a summary of principal relay terms and definitions in current British and international practice. It is not complete and further reference should be made to the following standards.

|                              |                                                                           |
|------------------------------|---------------------------------------------------------------------------|
| B.S. 142:1982                | Electrical Protective Relays.                                             |
| B.S. 5311:1976               | A.C. Circuit Breakers of Voltage above 1 kV                               |
| B.S. 3938:1982               | Current Transformers.                                                     |
| B.S. 3941:1982               | Voltage Transformers.                                                     |
| B.S. 4727:1971 (Part 1)      | Relay and Measurement Terminology                                         |
| B.S. 4727:1971 (Part 2)      | Terms Particular to Power Engineering                                     |
| B.S. 3939:1966-78            | Graphical Symbols for Electrical Equipment                                |
| C37-90:1978                  | American National Standard for Relays and Relay Systems                   |
| IEC 255 (1971-83) Parts 1-19 | International Electrotechnical Commission Standards for Electrical Relays |
| IEC 50 (446):1983            | International Electrotechnical Vocabulary: Electrical Relays              |

## **1.11**

### **LIST OF SYMBOLS**

|        |                             |
|--------|-----------------------------|
| A      | Alarm                       |
| AA     | Alarm acceptance            |
| ACC    | Acceleration                |
| ACCR   | Acceleration receive        |
| ACCS   | Acceleration send           |
| ACCS/R | Acceleration send/receive   |
| AN     | Annunciator                 |
| AUX    | Auxiliary                   |
| AVC    | Automatic voltage control   |
| AVR    | Automatic voltage regulator |
| AVS    | Automatic voltage selection |

|            |                                                  |
|------------|--------------------------------------------------|
| B          | Buchholz                                         |
| BAT E      | Battery earth fault                              |
| BB         | Busbar                                           |
| BLK        | Blocking                                         |
| BV         | Balanced voltage                                 |
| CA         | Check alarm or alarm cancellation                |
| CACL       | Carrier current, direction-comparison            |
| CAC $\phi$ | Carrier current, phase-comparison                |
| CC         | Circulating current                              |
| CK         | Check                                            |
| D          | Discriminating                                   |
| DAR        | Delayed auto-reclose                             |
| DEIT       | Directional earth fault, inverse time            |
| DIF        | Differential                                     |
| DIFB       | Biased differential                              |
| DIFPB      | Plain balance differential                       |
| DOCIT      | Directional overcurrent, inverse time            |
| DOCITI     | Directional overcurrent, inverse time, inhibited |
| E          | Earth fault, instantaneous                       |
| EIT        | Earth fault, inverse time                        |
| FE         | Frame earth fault                                |
| FFR        | Fuse failure                                     |
| FG         | Flag                                             |
| FP         | Feeder protection                                |
| FPFM       | Feeder protection, first main                    |
| FPSM       | Feeder protection, second main                   |
| FPBU       | Feeder protection, back-up                       |
| FPM        | Feeder protection, main                          |
| HSAR       | High speed auto-reclose                          |
| HSASC      | High speed ammeter shorting                      |
| HSOC       | High set overcurrent                             |
| I          | Current                                          |
| I OB       | Current out-of-balance                           |
| IP         | Interposing                                      |
| INT        | Intertrip                                        |
| INTR       | Intertrip receive                                |
| INTS       | Intertrip send                                   |
| INT S/R    | Intertrip send/receive                           |
| INTSPR     | Intertrip, surge proof, receive                  |
| INTSPS     | Intertrip, surge proof, send                     |
| LDC        | Line drop compensator                            |
| LE         | Loss excitation                                  |
| LFA        | Low frequency alarm                              |
| LFT        | Low frequency trip                               |
| LO         | Lock-out                                         |
| LP         | Low power                                        |
| LS         | Loss of synchronism                              |
| MCP        | Mesh corner protection                           |
| MHO        | High speed distance (mho)                        |
| MHO INT    | High speed distance (interlocked mho)            |
| NEFA       | Neutral earth fault alarm                        |
| NEF CK     | Neutral earth fault check                        |
| N $\phi$   | Negative phase sequence or phase unbalance       |
| NV         | No-volt                                          |
| NVD        | Neutral voltage displacement                     |
| OC         | Overcurrent, instantaneous                       |
| OCK        | Overcurrent check                                |
| OCDT       | Overcurrent, definite time                       |
| OCINT      | Overcurrent, interlocked                         |
| OCIT       | Overcurrent, inverse time                        |
| OF         | Overfrequency                                    |
| OL         | Overload                                         |
| OLA        | Overload alarm                                   |
| OV         | Overvoltage                                      |
| PCF        | Pilot channel fail                               |
| POP        | Post Office pilot                                |
| PP         | Private pilot                                    |
| PPH        | Positive phase sequence                          |
| PR         | Protective relay                                 |
| PS         | Pilot shorting                                   |
| PSF        | Pilot supply fail                                |
| PSS        | Protection d.c. supply supervision               |
| REF        | Restricted earth fault                           |

|          |                                       |
|----------|---------------------------------------|
| ROT      | Rotor earth fault                     |
| RP       | Reverse power                         |
| RPH      | Reverse phase                         |
| SBE      | Standby earth fault                   |
| ST       | Stalling                              |
| SY       | Selection (synchronizing)             |
| SYN      | Synchronizing                         |
| SYN AUTO | Automatic synchronizing               |
| SYN CK   | Check synchronizing                   |
| SYN SYS  | System synchronizing                  |
| SYS BU   | System back-up                        |
| T        | Tripping                              |
| TC       | Circuit breaker trip coil             |
| TCS      | Trip circuit supervision              |
| TD       | Definite time                         |
| TE       | Tripping, electrically reset          |
| T E/H    | Tripping, electrically and hand reset |
| TE RESET | Trip relay reset                      |
| TH       | Tripping, hand reset                  |
| THOC     | Thermal overcurrent                   |
| TM       | Time delay or timing relay            |
| TS       | Tripping, self reset                  |
| TSEQ     | Tripping, sequential                  |
| TSS      | Trip supply supervision               |
| UC       | Undercurrent                          |
| UF       | Underfrequency                        |
| UP       | Underpower                            |
| UV       | Undervoltage                          |
| UVIT     | Undervoltage, inverse time            |
| V        | Voltage                               |
| VR       | Voltage regulating                    |
| VS       | Voltage selection                     |
| X        | Distance (reactance)                  |
| Z        | Distance (impedance)                  |

## 1.12

|     |                                                       |
|-----|-------------------------------------------------------|
| 2   | Time delay starting or closing relay                  |
| 3   | Checking or interlocking relay                        |
| 4   | Master contactor                                      |
| 21  | Distance relay                                        |
| 25  | Synchronizing or synchronism check relay              |
| 27  | Undervoltage relay                                    |
| 30  | Annunciator relay                                     |
| 32  | Directional power relay                               |
| 37  | Undercurrent or underpower relay                      |
| 40  | Field failure relay                                   |
| 46  | Reverse phase or phase balance current relay          |
| 49  | Machine or transformer thermal relay                  |
| 50  | Instantaneous overcurrent or rate-of-rise relay       |
| 51  | A.c. time overcurrent relay                           |
| 52  | A.c. circuit breaker                                  |
| 52a | Circuit breaker auxiliary switch—normally open        |
| 52b | Circuit breaker auxiliary switch—normally closed      |
| 55  | Power factor relay                                    |
| 56  | Field application relay                               |
| 59  | Overvoltage relay                                     |
| 60  | Voltage or current balance relay                      |
| 64  | Earth fault protective relay                          |
| 67  | A.c. directional overcurrent relay                    |
| 68  | Blocking relay                                        |
| 74  | Alarm relay                                           |
| 76  | D.c. overcurrent relay                                |
| 78  | Phase angle measuring or out-of-step protective relay |
| 79  | A.c. reclosing relay                                  |
| 81  | Frequency relay                                       |
| 83  | Automatic selective control or transfer relay         |
| 85  | Carrier or pilot wire receive relay                   |
| 86  | Locking-out relay                                     |
| 87  | Differential protective relay                         |

### 1.13

#### CONTACT SYSTEMS

##### a. Self-reset.

The contacts remain operated only while the controlling quantity is applied, returning to their original condition when it is removed.

##### b. Hand or electrical reset.

These contacts remain in the operated position after the controlling quantity is removed. They can be reset either by hand or by an auxiliary electromagnetic element.

The majority of protective relay elements have self-reset contact systems, which, if it is so desired, can be made to give hand reset output contacts by the use of auxiliary elements.

Hand or electrically reset relays are used when it is necessary to maintain a signal or a lock-out condition. Contacts are shown on diagrams in the position corresponding to the un-operated or de-energized condition regardless of the continuous service condition of the equipment. For example, a voltage supervising relay, which is continually picked-up, would still be shown in the de-energized condition.

A 'make' contact is one that closes when the relay picks up, whereas a 'break' contact is one that is closed when the relay is un-energized and opens when the relay picks up. Examples of these conventions and variations are shown in Figure 1.6.

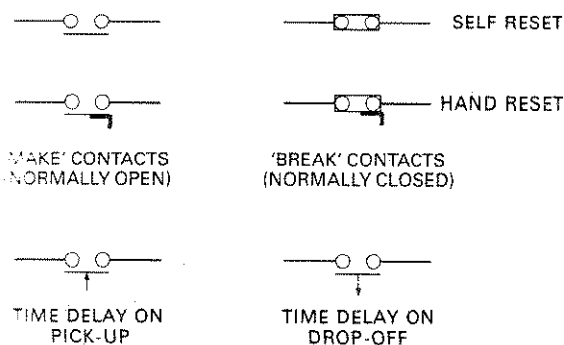


Figure 1.6 Indication of contacts on diagrams.

A protective relay is usually required to trip a circuit breaker, the tripping mechanism of which may be a solenoid with a plunger acting directly on the mechanism latch or, in the case of air-blast or pneumatically operated breakers, an electrically operated valve. The relay may energize the tripping coil directly, or, according to the coil rating, and the number of circuits to be energized, may do so through the agency of another multi-channel auxiliary relay.

The power required by the trip coil of the circuit breaker may range from up to 50 watts, for a small 'distribution' circuit breaker, to 3000 watts for a large extra-high-voltage circuit breaker.

The basic trip circuit is simple, being made up of a hand-trip control switch and the contacts of the protective relays in parallel to energize the trip coil from a battery, through a normally open auxiliary switch operated by the circuit breaker. This auxiliary switch is needed to open the trip circuit when the circuit breaker opens, since the protective relay contacts will usually be quite incapable of performing the interrupting duty. The auxiliary switch will be adjusted to close as early as possible in the closing stroke, to make the protection effective in case the breaker is being closed on to a fault.

Protective relays are precise measuring devices, the contacts of which should be not expected to perform large making and breaking duties. Attracted armature relays,

which combine many of the characteristics of measuring devices and contactors, occupy an intermediate position and according to their design and consequent closeness to one or other category, may have an appreciable contact capacity.

Most other types of relay develop an effort which is independent of the position of the moving system. At setting, the electromechanical effort is absorbed by the controlling force, the margin for operating the contacts being negligibly small. Not only does this limit the 'making' capacity of the contacts, but if more than one contact pair is fitted any slight misalignment may result in only one contact being closed at the minimum operating value, there being insufficient force to compress the spring of the first contact to make, by the small amount required to permit closure of the second.

For this reason, the provision of multiple contacts on such elements is undesirable. Although two contacts can be fitted, care must be taken in their alignment, and a small tolerance in the closing value of operating current may have to be allowed between them. These effects can be reduced by providing a small amount of 'run-in' to contact make in the relay behaviour, by special shaping of the active parts.

For the above reasons it is often better to use interposing contactor type elements which do not have the same limitations, although some measuring relay elements are capable of tripping the smaller types of circuit breaker directly. These may be small attracted armature type elements fitted in the same case as the measuring relay.

In general, static relays have discrete measuring and tripping circuits, or modules. The functioning of the measuring modules will not react on the tripping modules. Such a relay is equivalent to a sensitive electromechanical relay with a tripping contactor, so that the number or rating of outputs has no more significance than the fact that they have been provided.

For larger switchgear installations the tripping power requirement of each circuit breaker is considerable, and, further, two or more breakers may have to be tripped by one protective system. There may also be remote signalling requirements, interlocking with other functions (for example auto-reclosing arrangements), and other control functions to be performed. These various operations are carried out by multi-contact tripping relays, which are energized by the protection relays and provide the necessary number of adequately rated output contacts.

### 1.14

As a guide for power system operation staff, protective systems are invariably provided with indicating devices. In British practice these are called 'flags', whereas in America they are known as 'targets'. Not every component relay will have one, as indicators are arranged to operate only if a trip operation is initiated. Indicators, with very few exceptions, are bi-stable devices, and may be either mechanically or electrically operated. A mechanical indicator consists of a small shutter which is released by the protective relay movement to expose the indicator pattern, which, on GEC ALSTHOM Measurements relays, consists of red stripes on a white background.

Electrical indicators may be simple attracted armature elements either with or without contacts. Operation of the armature releases a shutter to expose an indicator as above.

An alternative type consists of a small cylindrical permanent magnet magnetized across a diameter, and lying between the poles of an electromagnet. The magnet, which is free to rotate, lines up its magnetic axis with the electromagnet poles, but can be made to reverse its

orientation by the application of a field. The edge of the magnet is coloured to give the indication.

In static relays the operation indicators increasingly take the form of light emitting diodes (LEDs).

## 1.15

Auxiliary contactors can be used to supplement protective relays in a number of ways:

- Series sealing.
  - Shunt reinforcing.
  - Shunt reinforcement with sealing.
- These are illustrated in Figure 1.7.

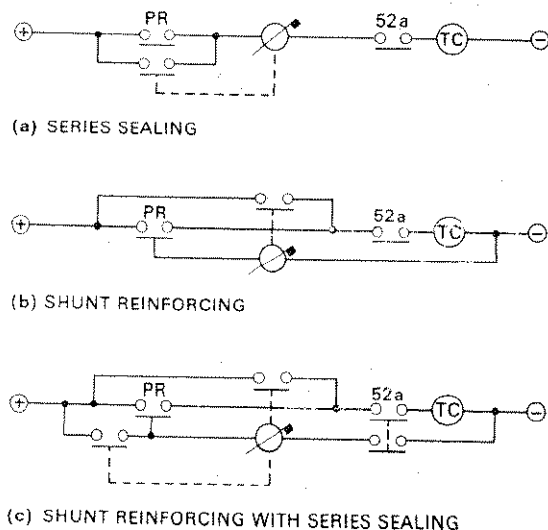


Figure 1.7 Typical relay tripping circuits.

When such auxiliary elements are fitted, they can conveniently carry the operation indicator, avoiding the need for indicators on the measuring elements.

Electrically operated indicators avoid imposing an additional friction load on the measuring element, which would be a serious handicap for certain types. Another advantage is that the indicator can operate only after the main contacts have closed. With indicators operated directly by the measuring elements, care must be taken to line up their operation with the closure of the main contacts. The indicator must have operated by the time the contacts make, but must not have done so more than marginally earlier. This is to stop indication occurring when the tripping operation has not been completed.

### a. Series sealing

The coil of the series contactor carries the trip current initiated by the protective relay and the contactor closes a contact in parallel with the protective relay contact. This closure relieves the protective relay contact of further duty and keeps the tripping circuit securely closed, even if chatter occurs at the main contact. Nothing is added to the total tripping time, and the indicator does not operate until current is actually flowing through the trip coil.

The main disadvantage of this method is that such series elements must have their coils matched with the trip circuit with which they are associated.

The coils of these contactors must be of low impedance, with about 5% of the trip supply voltage being dropped across them.

When used in association with high speed trip relays, which usually interrupt their own coil current, the auxiliary elements must be fast enough to operate and release the flag before their coil current is cut off. This may pose a

problem in design if a variable number of auxiliary elements (for different phases and so on) may be required to operate in parallel to energize a common tripping relay.

### b. Shunt reinforcing.

Here the sensitive contacts are arranged to trip the circuit breaker and simultaneously to energize the auxiliary unit, which then reinforces the contact which is energizing the trip coil.

It should be noted that two contacts are required on the protective relay, since it is not permissible to energize the trip coil and the reinforcing contactor in parallel. If this were done, and more than one protective relay were connected to trip the same circuit breaker, all the auxiliary relays would be energized in parallel for each relay operation and the indication would be confused.

The duplicate main contacts are frequently provided as a three point arrangement to reduce the number of contact fingers.

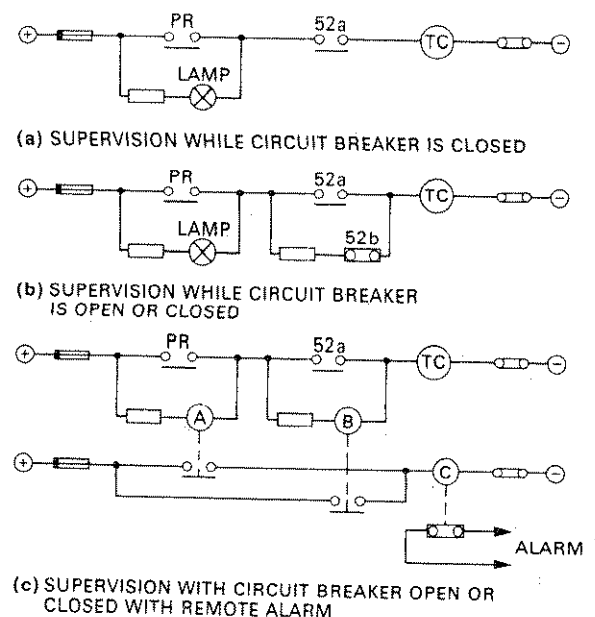


Figure 1.8 Examples of trip circuit supervision.

### c. Shunt reinforcement with sealing.

This is a development of the shunt reinforcing circuit to make it applicable to relays with low torque movements or where there is a possibility of contact bounce for any other reason.

Using the shunt reinforcing system under these circumstances would result in chattering on the auxiliary unit, and the possible burning out of the contacts not only of the sensitive element but also of the auxiliary unit. The chattering would end only when the circuit breaker had finally tripped.

It will be seen that the effect of bounce is countered by means of a further contact on the auxiliary unit connected as a retaining contact.

This means that provision must be made for releasing the sealing circuit when tripping is complete; this is a disadvantage, because it is sometimes inconvenient to find a suitable contact to use for this purpose.

## 1.16

### PROTECTION OF TRIP CIRCUITS

The trip circuit extends beyond the relay enclosure and passes through more components, such as fuses, links, relay contacts, auxiliary switch contacts and so on, and in some cases through a considerable amount of circuit

wiring with intermediate terminal boards. These complications, coupled with the importance of the circuit, have directed attention to its supervision.

The simplest arrangement contains a healthy trip lamp, as shown in Figure 1.8(a).

The resistance in series with the lamp prevents the breaker being tripped by an internal short circuit caused by failure of the lamp. This provides supervision while the circuit breaker is closed; a simple extension gives pre-closing supervision.

Figure 1.8(b) shows how, by the addition of a normally closed auxiliary switch and a resistance unit, supervision can be obtained while the breaker is both open and closed.

In either case, the addition of a normally open push-button contact in series with the lamp will make the supervision indication available only when required.

Schemes using a lamp to indicate continuity are suitable for locally controlled installations, but when control is exercised from a distance it is necessary to use a relay system. Figure 1.8(c) illustrates such a scheme, which is applicable wherever a remote signal is required.

With the circuit healthy either or both of relays *A* and *B* are operated and energize relay *C*. Both *A* and *B* must reset to allow *C* to drop-off. Relays *A*, *L*, *B* and *C* are time delayed by copper slugs to prevent spurious alarms during tripping or closing operations. The resistors are mounted separately from the relays and their values are chosen such that if any one component is inadvertently short-circuited, a tripping operation will not take place.

The alarm supply should be independent of the tripping supply so that indication will be obtained in the event of the failure of the tripping battery.





# Basic technology

- 2.1 Introduction
- 2.2 Vector algebra
- 2.3 Computation of complex quantities
- 2.4 Circuit quantities and conventions
- 2.5 Impedance notation
- 2.6 Basic circuit laws, theorems and network theory
- 2.7 4-phase fault calculations

## 2.1

### Introduction

The protection engineer is concerned with limiting the effects of disturbances in a power system, which, if allowed to persist, may damage plant and interrupt the supply of electric energy. These disturbances, described as faults (short circuits and open circuits) or power swings, result from natural hazards (for instance lightning), plant failure or human error.

To facilitate speedy removal of a disturbance from a power system, the system is divided into 'protection zones', and relays monitor the system quantities (current, voltage) appearing in these zones; if, for example, a fault occurs inside a zone, the relays operate to isolate the zone from the remainder of the power system.

The operating characteristic of a relay depends on the energizing quantities fed to it such as current or voltage, or various combinations of these two quantities, and also on the manner in which the relay is designed to respond to this information. For example, a directional relay characteristic would be obtained by designing the relay to compare the phase angle between voltage and current at the relaying point.

An impedance measuring characteristic, on the other hand, would be obtained by designing the relay to divide voltage by current. Many other more complex relay characteristics may be obtained by supplying various combinations of current and voltage to the relay.

It would usually be necessary to know the limiting values of current and voltage, and their relative phase displacement at the relay location for various types of short circuit and their position in the system. This would normally require some system analysis for faults occurring at various points in the system.

The main components that make up a power system are generating sources, transmission and distribution networks, and loads. Many transmission and distribution circuits radiate from key points in the system and these circuits are controlled by circuit breakers.

A typical power system is illustrated in Figure 2.1.

For the purpose of analysis, the system is treated as a network of circuit elements contained in branches radiating from nodes to form closed loops or meshes. The system variables are current and voltage, and in steady state analysis they are regarded as harmonically varying with time, at a single and constant frequency. The network

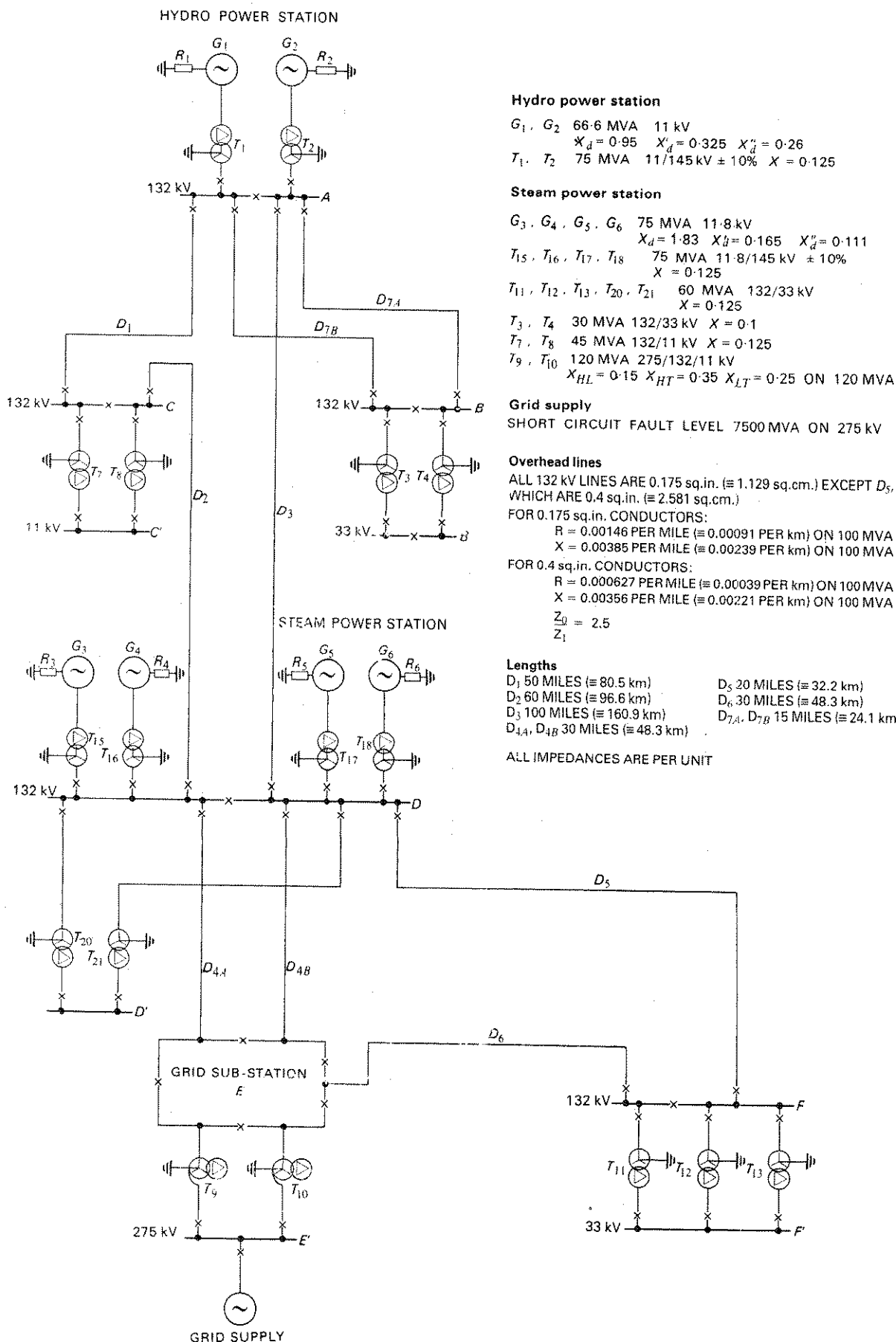


Figure 2.1 (a) Typical power system network.



parameters are impedance and admittance; these are assumed to be linear, bilateral (independent of current direction) and constant for a constant frequency.

## 2.2

A vector represents a quantity in both magnitude and direction. In Figure 2.2 the vector  $OP$  has a magnitude  $|Z|$  at an angle  $\theta$  with the reference axis  $OX$ .

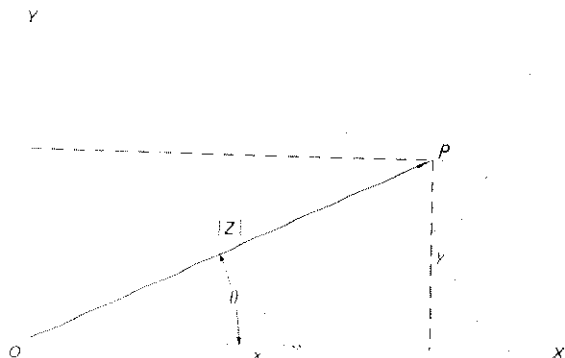


Figure 2.2 Vector  $OP = \bar{Z} = |Z| \angle \theta$

It may be resolved into two components at right angles to each other, in this case  $x$  and  $y$ . The magnitude or scalar value of vector  $\bar{Z}$  is known as the modulus  $|Z|$ , and the angle  $\theta$  is the argument, or amplitude, and is written as  $\arg. \bar{Z}$ . The conventional method of expressing a vector  $\bar{Z}$  is to write simply  $|Z| \angle \theta$ . This form completely specifies a vector for graphical representation or conversion into other forms.

For vectors to be useful they must be expressed algebraically. In Figure 2.2 the vector  $\bar{Z}$  is the resultant of vectorially adding its components  $x$  and  $y$ ; algebraically this vector may be written as:

$$\bar{Z} = x + jy \quad \dots \text{Equation 2.1}$$

where the  $j$  indicates that the component  $y$  is perpendicular to component  $x$ . In electrical nomenclature, the axis  $OX$  is the 'real' or 'in phase' axis, and the vertical axis  $OY$  is called the 'imaginary' or 'quadrature' axis. The symbol  $j$ , which is compounded with the quadrature component  $y$ , may be considered as an operator which rotates a vector anti-clockwise through  $90^\circ$ . If a vector is made to rotate anti-clockwise through  $180^\circ$ , then the operator  $j$  has performed its function twice, and since the vector has reversed its sense, then:

$$jj \text{ or } j^2 = -1$$

whence  $j = \sqrt{-1}$ .

The representation of a vector quantity algebraically in terms of its rectangular co-ordinates is called a 'complex quantity'. Therefore,  $x + jy$  is a complex quantity and is the rectangular form of the vector  $|Z| \angle \theta$  where:

$$\left. \begin{aligned} |Z| &= \sqrt{x^2 + y^2} & \theta &= \tan^{-1} y/x \\ \text{and} & & & \\ x &= |Z| \cos \theta & y &= |Z| \sin \theta \end{aligned} \right\} \dots \text{Equation 2.2}$$

From Equations 2.1 and 2.2:

$$\bar{Z} = |Z| (\cos \theta + j \sin \theta) \quad \dots \text{Equation 2.3}$$

and since  $\cos \theta$  and  $\sin \theta$  may be expressed in exponential form by the identities:

$$\sin \theta = \frac{e^{j\theta} - e^{-j\theta}}{2j}$$

$$\cos \theta = \frac{e^{j\theta} + e^{-j\theta}}{2}$$

it follows that  $\bar{Z}$  may also be written as:

$$\bar{Z} = |Z| e^{j\theta} \quad \dots \text{Equation 2.4}$$

Therefore, a vector quantity may also be represented trigonometrically and exponentially.

## 2.3

Complex quantities may be represented in any of the four forms given below.

- Conventional  $|Z| \angle \theta$
- Rectangular  $x + jy$
- Trigonometric  $|Z| (\cos \theta + j \sin \theta)$
- Exponential  $|Z| e^{j\theta}$

The modulus  $|Z|$  and the argument  $\theta$  are together known as 'polar co-ordinates', and  $x$  and  $y$  are described as 'cartesian co-ordinates'. It can be seen that provided one set of co-ordinates is known the other set can be derived, and manipulation of complex quantities can be carried out using any of the above forms.

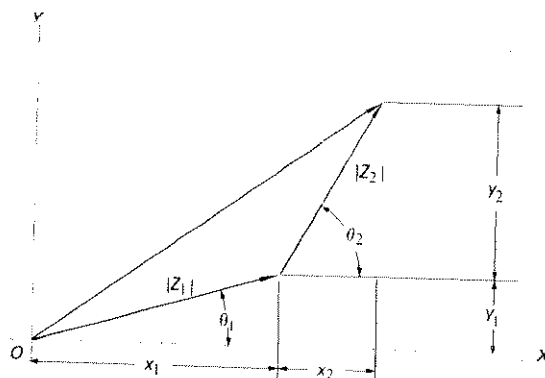


Figure 2.3 Addition of two vectors  $|Z_1| \angle \theta_1$  and  $|Z_2| \angle \theta_2$

### 2.3.1

#### Addition and subtraction

Figure 2.3 illustrates the addition of two vectors,  $\bar{Z}_1 = |Z_1| \angle \theta_1$ ,  $\bar{Z}_2 = |Z_2| \angle \theta_2$ . The resultant vector is the sum of the real and imaginary components of the vectors treated separately. So, using cartesian co-ordinates:

$$\begin{aligned} \bar{Z}_1 + \bar{Z}_2 &= (x_1 + jy_1) + (x_2 + jy_2) \\ \bar{Z}_1 + \bar{Z}_2 &= (x_1 + x_2) + j(y_1 + y_2) \end{aligned} \quad \dots \text{Equation 2.5}$$

Similarly:

$$\bar{Z}_1 - \bar{Z}_2 = (x_1 - x_2) + j(y_1 - y_2) \quad \dots \text{Equation 2.6}$$

From the diagram and the above equations it can be seen that provided  $j$  is regarded as obeying the ordinary laws of algebra, complex quantities in rectangular form can be manipulated algebraically.

### 2.3.2

#### Multiplication and division

Using the rectangular form and applying the ordinary laws of algebra:

$$\begin{aligned} \bar{Z}_1 \bar{Z}_2 &= (x_1 + jy_1)(x_2 + jy_2) \\ &= x_1x_2 + jx_1y_2 + jx_2y_1 + j^2y_1y_2 \end{aligned}$$

Since  $j^2 = -1$

$$\bar{Z}_1 \bar{Z}_2 = (x_1 x_2 - y_1 y_2) + j(x_1 y_2 + x_2 y_1) \quad \dots \text{Equation 2.7}$$

Now,  $x_1, x_2$  are cosine functions and  $y_1, y_2$  are sine functions. Thus, the real term in the resultant vector product is identically equal to  $|Z_1| |Z_2| \cos(\theta_1 + \theta_2)$ ; and the imaginary term is identically equal to  $|Z_1| |Z_2| \sin(\theta_1 + \theta_2)$ . Converting into the conventional form, using polar co-ordinates.

$$\bar{Z}_1 \bar{Z}_2 = |Z_1| |Z_2| \angle \theta_1 + \theta_2 \quad \dots \text{Equation 2.8}$$

In words, 'to multiply two vectors, take the product of their moduli and the sum of their arguments'.

Similarly, it can be shown that:

$$\frac{\bar{Z}_1}{\bar{Z}_2} = \frac{|Z_1|}{|Z_2|} \angle \theta_1 - \theta_2 \quad \dots \text{Equation 2.9}$$

In words, 'to divide two vectors, take the quotient of their moduli and the difference of their arguments'.

### 2.3.3

#### Complex variables

Some complex quantities are variable with, for example, time: when manipulating such variables in differential equations it is expedient to write the complex quantity in exponential form.

When dealing with such functions it is important to appreciate that the quantity contains real and imaginary components. If it is required to investigate only one component of the complex variable, the rule is that separation into components must be carried out after the mathematical operation has taken place.

Example: Determine the rate of change of the real component of a vector  $|Z| \angle \omega t$  with time.

$$\begin{aligned} Z \angle \omega t &= |Z| (\cos \omega t + j \sin \omega t) \\ &= |Z| e^{j\omega t} \end{aligned}$$

The real component of the vector is  $|Z| \cos \omega t$ .

Differentiating  $|Z| e^{j\omega t}$  with respect to time:

$$\begin{aligned} \frac{d}{dt} (Z e^{j\omega t}) &= j\omega |Z| e^{j\omega t} \\ &= j\omega |Z| (\cos \omega t + j \sin \omega t). \end{aligned}$$

Separating into real and imaginary components:

$$\frac{d}{dt} (Z e^{j\omega t}) = |Z| (-\omega \sin \omega t + j\omega \cos \omega t).$$

Thus, the rate of change of the real component of a vector  $Z \angle \omega t$  is:

$$-|Z| \omega \sin \omega t$$

### 2.3.4

#### Complex numbers

A complex number may be defined as a constant which represents the real and imaginary components of a physical quantity. The impedance parameter of an electric circuit is a complex number having real and imaginary components, which are described as resistance and reactance respectively.

Confusion often arises between vectors and complex numbers. A vector, as previously defined, may be a complex number. In this context it is simply a physical quantity of constant magnitude acting in a constant direction. A complex number, which, while being a physical quantity, relates stimulus and response in a given operation is known as a 'complex operator'. In this context it is distinguished from a vector by the fact that it has no direction of its own.

Because complex numbers assume a passive role in any calculation, the method of representing them is determined by the form taken by the variables in the problem.

### 2.3.5

#### Operators

Operators are complex numbers which are used to move a vector through a given angle without changing the magnitude or character of the vector. An operator is not a physical quantity; it is dimensionless.

The symbol  $j$ , which has been compounded with quadrature components of complex quantities, may be regarded as an operator which rotates a quantity anti-clockwise through  $90^\circ$ . Another useful operator is one which moves a vector anti-clockwise through  $120^\circ$ , variously represented by symbols  $a$ ,  $h$ , and  $\lambda$ . The symbol  $a$  is the most familiar symbol for this operator and is the one adopted in this book.

Operators are distinguished by one further feature; they are roots of unity. Using De Moivre's theorem, the  $n$ th root of unity is given by solving the expression:

$$1^{1/n} = (\cos 2\pi m + j \sin 2\pi m)^{1/n}$$

where  $m$  is any integer. Whence:

$$1^{1/n} = \cos \frac{2\pi m}{n} + j \sin \frac{2\pi m}{n}$$

where  $m$  has values  $1, 2, 3, \dots (n-1)$ .

From the above expression  $j$  is found to be the 4th root and  $a$  the 3rd root of unity, as they have four and three distinct values respectively. Table 2.1 gives some useful functions of the  $a$  operator.

$$a = -\frac{1}{2} + j \frac{\sqrt{3}}{2} = e^{j\frac{2\pi}{3}}$$

$$a^2 = -\frac{1}{2} - j \frac{\sqrt{3}}{2} = e^{j\frac{4\pi}{3}}$$

$$1 = 1 + j0 = e^{j0}$$

$$1 + a + a^2 = 0 \quad a - a^2 = j\sqrt{3}$$

$$1 - a = j\sqrt{3}a^2 \quad j = \frac{a - a^2}{\sqrt{3}}$$

$$1 - a^2 = -j\sqrt{3}a$$

Table 2.1 Some useful functions of the  $a$  operator

### 2.4

#### CIRCUIT QUANTITIES AND CONVENTIONS

Circuit analysis may be described as the study of the response of a circuit to an imposed condition, for example short circuit. The circuit variables are current and voltage. Conventionally, current flow results from the application of a driving voltage, but there is complete duality between the variables and either may be regarded as the cause of the other.

When a circuit exists there is an interchange of energy; a circuit may be described as being made up of 'sources' and 'sinks' for energy. The parts of a circuit are described as elements; a 'source' may be regarded as an 'active' element and a 'sink' as a 'passive' element. Some circuit elements are dissipative, that is, they are continuous sinks for energy, for example resistance. Other circuit elements may be alternatively sources and sinks, for example capacitance and inductance. The elements of a circuit are connected together to form a network having nodes (terminals) and branches (series groups of elements) which form closed loops (meshes). In Figure 2.4 the symbols for the circuit elements are reproduced.

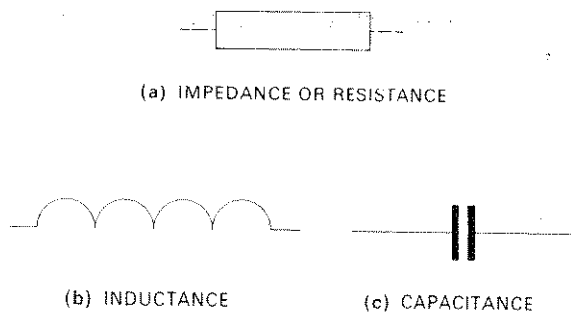


Figure 2.4 General circuit symbols

In steady state a.c. circuit theory, the ability of a circuit to accept a current flow resulting from a given driving voltage is called the impedance of the circuit. Since current and voltage are duals the impedance parameter must also have a dual. It is called admittance. The current and voltage are assumed to be sinusoidal functions of time having a single and constant frequency, and the circuit parameters (impedance and admittance) are regarded as being linear, bilateral (independent of current direction) and constant in value for a constant frequency.

### 2.4.1 Circuit variables

As current and voltage are sinusoidal functions of time, varying at a single and constant frequency, they are regarded as rotating vectors and can be drawn as plane vectors (that is, vectors defined by two co-ordinates) on a vector diagram.

For example, the instantaneous value,  $e$ , of a voltage varying sinusoidally with time is:

$$e = E_m \sin(\omega t + \delta) \quad \dots \text{Equation 2.10}$$

where  $E_m$  is the maximum amplitude of the waveform;  $\omega = 2\pi f$ , the angular velocity, where  $f$  is the frequency;  $\delta$  is the argument defining the amplitude of the voltage at a time  $t = 0$ .

At  $t = 0$ , the actual value of the voltage is  $E_m \sin \delta$ . So if  $E_m$  is regarded as the modulus of a vector whose argument is  $\delta$ , then  $E_m \sin \delta$  is the imaginary component of the vector  $|E_m| \angle \delta$ . Figure 2.5 illustrates this quantity as a vector and as a sinusoidal function of time.

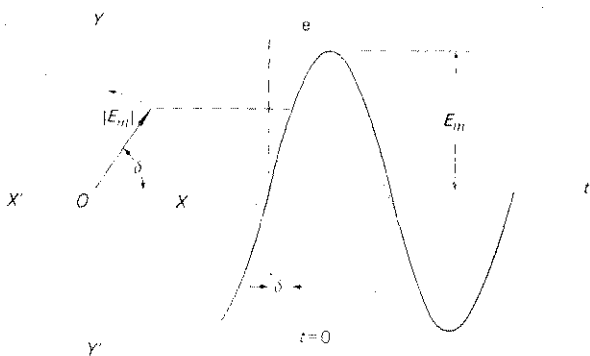


Figure 2.5 Representation of a sinusoidal function.

The current resulting from applying a voltage to a circuit depends upon the circuit impedance. If the voltage is a sinusoidal function at a given frequency and the impedance is constant the current will also vary harmonically at the same frequency, so it can be shown on the same vector diagram as the voltage vector, and may be given by the equation:

$$i = \frac{|E_m|}{|Z|} \sin(\omega t + \delta - \phi) \quad \dots \text{Equation 2.11}$$

where

$$\left. \begin{aligned} |Z| &= \sqrt{R^2 + X^2} \\ X &= \left( \omega L - \frac{1}{\omega C} \right) \\ \phi &= \tan^{-1} X/R \end{aligned} \right\} \quad \dots \text{Equation 2.12}$$

From Equations 2.11 and 2.12 it can be seen that the angular displacement  $\phi$  between the current and voltage vectors and the current magnitude  $|I_m| = |E_m|/|Z|$  is dependent upon the impedance  $\bar{Z}$ . In complex form the impedance may be written  $\bar{Z} = R + jX$ . The 'real component',  $R$ , is the circuit resistance, and the 'imaginary component',  $X$ , is the circuit reactance. When the circuit reactance is inductive (that is,  $\omega L > 1/\omega C$ ) the current 'lags' the voltage by an angle  $\phi$ , and when it is capacitive (that is,  $1/\omega C > \omega L$ ) it 'leads' the voltage by an angle  $\phi$ .

The usual convention adopted when drawing vector diagrams is to choose one vector as the 'reference vector' and relate the other vector to it in terms of the angle of lag or lead and the numerical or scalar magnitudes. The quantity  $|Z|$  described as the circuit impedance is a complex operator and is distinguished from a vector only by the fact that it has no direction of its own. A further convention is that sinusoidally varying quantities are described by their 'effective' or 'root mean square' (r.m.s.) values; these are usually written using the quantity symbol without a suffix. Thus:

$$\left. \begin{aligned} |I| &= |I_m|/\sqrt{2} \\ |E| &= |E_m|/\sqrt{2} \end{aligned} \right\} \quad \dots \text{Equation 2.13}$$

The 'root mean square' value is that value which has the same heating effect as a direct current quantity of that value in the same circuit, and this definition applies to non-sinusoidal as well as sinusoidal quantities.

### 2.4.2 Voltage rise, voltage drop, assumed direction of positive current flow, notation

In describing the electrical state of a circuit it is often necessary to refer to the 'potential difference' existing between two points in the circuit. Since wherever such a potential difference exists, current will flow and energy will either be transferred or absorbed it is obviously necessary to define a potential difference in more exact terms. For this reason the terms voltage rise and voltage drop are used to define more accurately the nature of the potential difference.

Voltage rise is a rise in potential measured in the direction of current flow between two points in a circuit, and energy is transferred from that part of the circuit in which the rise has taken place, to the remainder of the circuit. Thus a voltage rise is a driving voltage developed across that part of a circuit containing active elements, and therefore may be regarded as a source of energy.

Voltage drop is a drop in potential measured in the direction of current flow, between two points in a circuit, and energy is absorbed over that part of the circuit in which the drop has taken place. Thus a voltage drop is a passive voltage existing across that part of a circuit containing passive elements, and therefore may be regarded as a sink for energy.

Kirchoff's first law states that the sum of the driving voltages must equal the sum of the passive voltages in a closed loop. This is illustrated by the fundamental equation of an electric circuit:

$$iR + \frac{L di}{dt} + \frac{1}{C} \int i dt = e \quad \dots \text{Equation 2.14}$$

where the terms on the left hand side of the equation are voltage drops across the circuit elements. Expressed in steady state terms Equation 2.14 may be written:

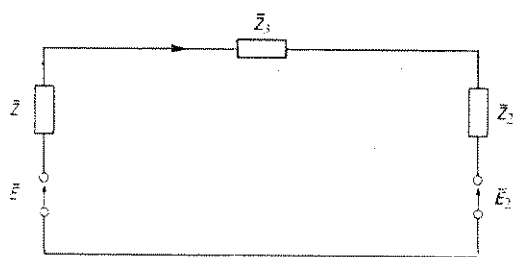
$$\sum \bar{E} = \sum \bar{I}\bar{Z} \quad \dots \text{Equation 2.15}$$

and this is known as the equated-voltage equation.

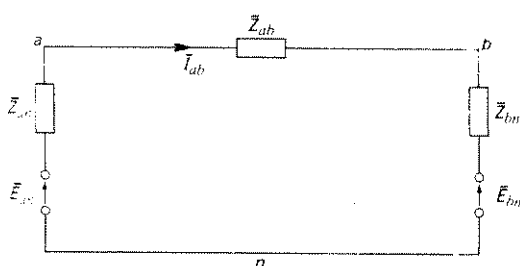
It is the equation most usually adopted in electrical network calculations, since it equates the driving voltages, which are known, to the passive voltages, which are functions of the currents to be calculated. In describing circuits and drawing vector diagrams, for formal analysis or calculations, it is necessary to adopt a notation which defines the positive direction of assumed current flow, and establishes the direction in which positive voltage drops and voltage rises act. Two methods are available; one, the double suffix method, is used for symbolic analysis, the other, the single suffix or diagrammatic method, is used for numerical calculations.

In the double suffix method the positive direction of current flow is assumed to be from node  $a$  to node  $b$  and the current is designated  $\bar{I}_{ab}$ . With the diagrammatic method the direction of current flow is indicated by an arrow.

The voltage rises are positive when acting in the direction of current flow. It can be seen from Figure 2.6 that  $\bar{E}_1$  and  $\bar{E}_2$  are positive voltage rises and  $\bar{E}_3$  and  $\bar{E}_{bn}$  are negative voltage rises. In the diagrammatic method their direction of action is simply indicated by an arrow, whereas in the double suffix method,  $\bar{E}_{an}$  and  $\bar{E}_{bn}$  indicate that there is a potential rise in directions  $na$  and  $nb$ .



(a) DIAGRAMMATIC  
 $\bar{E}_1 - \bar{E}_2 = (\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_3) \bar{I}$



(b) DOUBLE SUFFIX  
 $\bar{E}_{an} - \bar{E}_{bn} = (\bar{Z}_{an} + \bar{Z}_{ab} + \bar{Z}_{bn}) \bar{I}_{ab}$

Figure 2.6 Methods of representing a circuit.

Voltage drops are also positive when acting in the direction of current flow. From figure 2.6(a) it can be seen that  $\bar{E}_1 - \bar{E}_2 = (\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_3) \bar{I}$  is the total voltage drop in the loop in the direction of current flow, and must equate to the total voltage rise  $\bar{E}_1 - \bar{E}_2$ . In Figure 2.6(b), the voltage drop between nodes  $a$  and  $b$  designated  $\bar{V}_{ab}$  indicates that point  $b$  is at a lower potential than  $a$ , and is positive when current flows from  $a$  to  $b$ . Conversely  $\bar{V}_{ba}$  is a negative voltage drop.

Symbolically:

$$\begin{aligned} \bar{V}_{ab} &= \bar{V}_{an} - \bar{V}_{bn} \\ \text{and } \bar{V}_{ba} &= \bar{V}_{bn} - \bar{V}_{an} \end{aligned} \quad \dots \text{Equation 2.16}$$

where  $n$  is a common reference point.

### 2.4.3 Power

The product of the potential difference across and the current through a branch of a circuit is a measure of the rate at which energy is exchanged between that branch and the remainder of the circuit. If the potential difference is a positive voltage drop the branch is passive and absorbs energy. Conversely, if the potential difference is a positive voltage rise the branch is active and supplies energy.

The rate at which energy is exchanged is known as power, and by convention, the power is positive when energy is being absorbed and negative when being supplied. With a.c. circuits the power alternates, so, to obtain a rate at which energy is supplied or absorbed it is necessary to take the average power over one whole cycle. If  $e = E_m \sin(\omega t + \delta)$  and  $i = I_m \sin(\omega t + \delta - \phi)$  then the power equation is:

$$p = ei = P[1 - \cos 2(\omega t + \delta)] + Q \sin 2(\omega t + \delta) \quad \dots \text{Equation 2.17}$$

where  $P = |E| |I| \cos \phi$  and  $Q = |E| |I| \sin \phi$ .

From Equation 2.17 it can be seen that the quantity  $P$  varies from 0 to  $2P$  and quantity  $Q$  varies from  $-Q$  to  $+Q$  in one cycle, and that the waveform is of twice the periodic frequency of the current and voltage waveforms.

The average value of the power exchanged in one cycle is a constant, equal to quantity  $P$ , and as this quantity is the product of the voltage and the component of current which is 'in phase' with the voltage it is known as the 'real' or 'active' power.

The average value of quantity  $Q$  is zero when taken over a cycle, suggesting that energy is stored in one half-cycle and returned to the circuit in the remaining half-cycle.  $Q$  is the product of voltage and the quadrature component of current, and is known as 'reactive power'.

As  $P$  and  $Q$  are constants which specify the power exchange in a given circuit, and are products of the current and voltage vectors, then if  $\bar{S}$  is the vector product  $\bar{E}\bar{I}$  it follows that with  $\bar{E}$  as the reference vector and  $\phi$  as the angle between  $\bar{E}$  and  $\bar{I}$ :

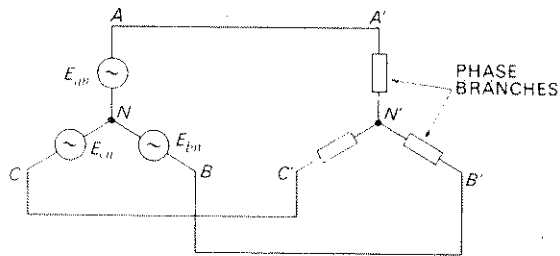
$$\bar{S} = P + jQ \quad \dots \text{Equation 2.18}$$

The quantity  $\bar{S}$  is described as the 'apparent power', and is the term used in establishing the rating of a circuit.

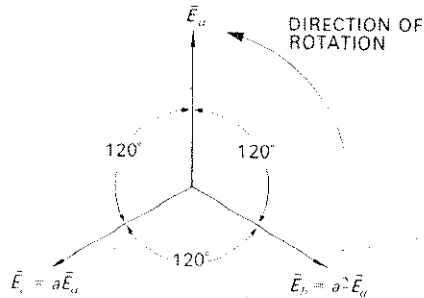
### 2.4.4 Single-phase and polyphase systems

A system is single or polyphase depending upon whether the sources feeding it are single or polyphase. A source is single or polyphase according to whether there is one or several driving voltages associated with it. For example, a three-phase source is a source containing three alternating driving voltages which are assumed to reach a maximum in phase order,  $A, B, C$ . Each phase driving voltage is associated with a phase branch of the system network as shown in Figure 2.7(a).

If a polyphase system has balanced voltages, that is, equal in magnitude and reaching a maximum at equally displaced time intervals, and the phase branch impedances are identical, then the system is said to be 'balanced'. It will become 'unbalanced' if the above conditions are not satisfied. When a polyphase system can be regarded as balanced, calculations are simplified as it is only necessary to



(a) THREE-PHASE SYSTEM



(b) BALANCED SYSTEM OF VECTORS

Figure 2.7 Three-phase systems.

solve for a single phase, the solution for the remaining phases being obtained by symmetry.

The power system is normally operated as a three-phase, balanced, system. For this reason the phase voltages are equal in magnitude and can be represented by three vectors spaced  $120^\circ$  or  $2\pi/3$  radians apart, as shown in Figure 2.7(b).

Since the voltages are symmetrical, they may be expressed in terms of one, that is:

$$\left. \begin{aligned} \bar{E}_u &= \bar{E}_u \\ \bar{E}_v &= a^2 \bar{E}_u \\ \bar{E}_w &= a \bar{E}_u \end{aligned} \right\} \quad \dots \text{Equation 2.19}$$

where  $a$  is the vector operator  $e^{j2\pi/3}$ . Further, if the phase branch impedances are identical in a balanced system, it follows that the resulting currents are also balanced.

## 2.5

It can be seen by perusing any power system diagram that there are several voltage levels in a system, that it is common practice to refer to plant MVA in terms of per unit or percentage values, and that transmission line and cable constants are given in ohms/km or ohms/mile. Before any system calculations can take place the system parameters must be referred to 'base quantities' and represented as a unified system of impedances in either ohmic, percentage, or per unit values.

The base quantities are power and voltage. Normally, they are given in terms of the three-phase power in MVA and the line voltage in kV. The base impedance resulting from the above base quantities is:

$$Z_b = \frac{(\text{kV})^2}{\text{MVA}} \text{ ohms} \quad \dots \text{Equation 2.20}$$

and provided the system is balanced, that is, with balanced current flow due to balanced driving voltages being applied to symmetrical impedances in the three phase branches, the base impedance may be calculated using either single-phase or three-phase quantities.

The per unit or percentage value of any impedance in the

system is the ratio of actual and base impedance values. Hence:

$$\left. \begin{aligned} Z \text{ p.u.} &= Z (\text{ohms}) \times \frac{\text{base MVA}}{(\text{base kV})^2} \\ Z\% &= Z \text{ p.u.} \times 100 \end{aligned} \right\} \quad \dots \text{Equation 2.21}$$

Simple transposition of the above formula will refer the ohmic value of impedance to the per unit or percentage values and base quantities.

It has already been stated that the system may operate at different voltage levels and it is obvious that plant ratings will vary considerably. Having chosen base quantities of suitable magnitude all system impedances may be converted to those base quantities by using the equations given below:

$$\left. \begin{aligned} Z \text{ p.u. (new base MVA)} \\ &= Z \text{ p.u. (given base MVA)} \times \frac{\text{new base MVA}}{\text{given base MVA}} \\ Z \text{ p.u. (new base kV)} \\ &= Z \text{ p.u. (given base kV)} \times \left( \frac{\text{given base kV}}{\text{new base kV}} \right)^2 \end{aligned} \right\} \quad \dots \text{Equation 2.22}$$

The choice of impedance notation depends upon the complexity of the system, plant impedance notation and the nature of the system calculations envisaged.

If the system is relatively simple and contains mainly transmission line data, given in ohms, then the ohmic method can be adopted with advantage. However, choosing a base voltage, and unifying system impedances to this base, should be approached with caution, as shown in the following example.

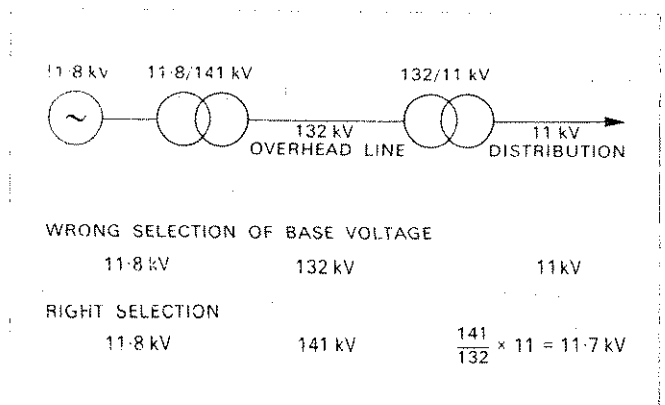


Figure 2.8 Selection of base voltages.

From Figure 2.8 it can be seen that the base voltages in the three circuits are in the ratio of the intervening transformers. Therefore, the rule is: 'to refer an impedance in ohms from one circuit to another multiply the given impedance by the square of the voltage ratio of the intervening transformer'.

The per unit method of impedance notation is the most advantageous for general system studies for two reasons:

- Impedances are the same referred to either side of a transformer if the ratio of base voltages on the two sides of a transformer is equal to the transformer turns ratio.
- Confusion caused by the introduction of powers of 100 in percentage calculation is avoided.

For example, in Figure 2.9 generators  $G_1$  and  $G_2$  have a sub-transient reactance of 26% on 66.6 MVA rating at 11 kV, and transformers  $T_1$  and  $T_2$  a voltage ratio of 11/145 kV and an impedance of 12.5% on 75 MVA. Choosing 100 MVA as base MVA and 132 kV as base voltage, find the percentage impedances to new base quantities.



a. Generator reactances to new bases are:

$$26 \times \frac{100}{66.6} \times \frac{(11)^2}{(132)^2} = 0.27\%$$

b. Transformer reactances to new bases are:

$$12.5 \times \frac{100}{75} \times \frac{(145)^2}{(132)^2} = 20.1\%$$

NOTE: The base voltages of the generator and circuits are 11 kV and 145 kV respectively, that is, the turns ratio of the transformer. The corresponding per unit values can be found by dividing by 100, and the ohmic value can be found by using Equation 2.21.

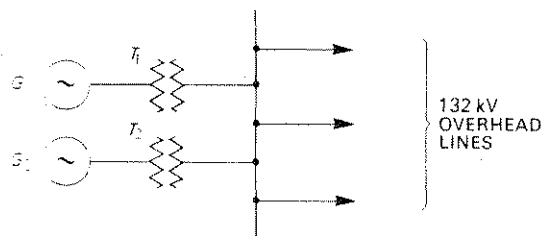


Figure 2.9 Section of the power system.

## 2.6

Most practical power system problems are solved by using steady state analytical methods. The assumptions made are that the circuit parameters are linear and bilateral and constant for constant frequency circuit variables. In some problems, described as initial value problems, it is necessary to study the behaviour of a circuit in the transient state. Such problems can be solved using operational methods. Again in other problems, which fortunately are few in number, the assumption of linear, bilateral circuit parameters is no longer valid. These problems are solved using advanced mathematical techniques which are beyond the scope of this book.

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### 2.6.1

#### Circuit laws

In linear, bilateral circuits, three basic network laws apply, regardless of the state of the circuit, at any particular instant of time. These laws are the branch, junction and mesh laws due to Ohm and Kirchoff, and are stated below, using steady state a.c. nomenclature.

##### Branch law

The current  $\bar{I}$  in a given branch of impedance  $\bar{Z}$  is proportional to the potential difference  $\bar{V}$  appearing across the branch, that is,  $\bar{V} = \bar{I}\bar{Z}$ .

##### Junction law

The algebraic sum of all current entering any junction (or node) in a network is zero, that is:

$$\sum \bar{I} = 0$$

Alternatively, if the currents directed towards any node are considered positive and the currents directed away from it are negative, then the sum of the currents that meet in the node is zero.

##### Mesh law

The algebraic sum of all the driving voltages in any closed path (or mesh) in a network is equal to the algebraic sum

*Electrical Network Calculations. D. E. Richardson, Van Nostrand.*

of all the passive voltages (products of the impedances and the currents) in the component branches, that is:

$$\sum \bar{E} = \sum \bar{I}\bar{Z}$$

Alternatively, the total change in potential around a closed loop is zero.

### 2.6.2

#### Circuit theorems

From the above network laws many theorems have been derived for the rationalization of networks, either to reach a quick, simple, solution to a problem or to represent a complicated circuit by an equivalent. These theorems are divided into two classes: those concerned with the general properties of networks and those concerned with network reduction.

Of the many theorems available (Richardson quotes thirty-three\*), three are given, namely the Superposition Theorem, Thévenin's Theorem and Kennelly's Star/Delta Theorem.

##### Superposition theorem (general network theorem)

The resultant current that flows in any branch of a network due to the simultaneous action of several driving voltages is equal to the algebraic sum of the component currents due to each driving voltage acting alone with the remainder short-circuited.

##### Thévenin's theorem (active network reduction theorem)

Any active network which may be viewed from two terminals can be replaced by a single driving voltage acting in series with a single impedance. The driving voltage is the open-circuit voltage between the two terminals and the impedance is the impedance of the network viewed from the terminals with all sources short-circuited.

##### Kennelly's star/delta theorem (passive network reduction theorem)

Any three-terminal network can be replaced by a delta or a star impedance equivalent without disturbing the external network. The impedance of a Y-branch lying between and replacing a pair of delta-branches is equal to the product of the impedances of those branches divided by the sum of the impedances in the delta loop, that is:

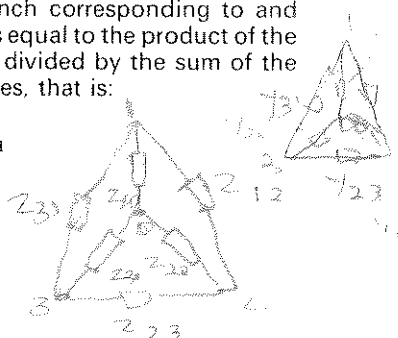
$$\bar{Z}_{10} = \bar{Z}_{12}\bar{Z}_{13}/(\bar{Z}_{12} + \bar{Z}_{23} + \bar{Z}_{31}) \text{ and so on.}$$

The admittance of a delta-branch corresponding to and replacing any two Y-branches is equal to the product of the admittances of those branches divided by the sum of the admittances of all three branches, that is:

$$\bar{Y}_{12} = \frac{\bar{Y}_{10}\bar{Y}_{20}}{\bar{Y}_{10} + \bar{Y}_{20} + \bar{Y}_{30}} \text{ and so on}$$

or, in terms of impedance:

$$\bar{Z}_{12} = \bar{Z}_{10} + \bar{Z}_{20} + \frac{\bar{Z}_{10}\bar{Z}_{20}}{\bar{Z}_{30}}$$



### 2.6.3

#### Network reduction

The aim of network reduction is to reduce a system to a simple equivalent while retaining the identity of that part of the system to be studied.

For example, consider the system shown in Figure 2.10. The network is the positive sequence diagram of a typical power system having two sources  $E'$  and  $E''$ , a line  $AOB$  shunted by an impedance, which may be regarded as the reduction of a further network connected between  $A$  and  $B$ , and a load connected between  $O$  and  $N$ . The object of the reduction is to study the effect of opening a breaker

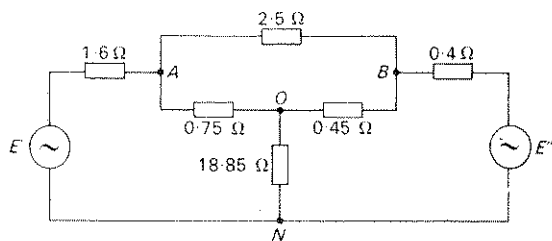


Figure 2.10 Typical power system network.

at *A* or *B* during normal system operations, or of a fault at *A* or *B*. Thus the identity of nodes *A* and *B* must be retained together with the sources, but the branch *ON* can be eliminated, simplifying the study. Proceeding, *A*, *B*, *N*, forms a star branch and can therefore be converted to an equivalent delta.

$$Z_{AN} = Z_{AO} + Z_{NO} + \frac{Z_{AO}Z_{NO}}{Z_{BO}}$$

$$= 0.75 + 18.85 + \frac{0.75 \times 18.85}{0.45}$$

$$= 51 \text{ ohms}$$

$$Z_{BN} = Z_{BO} + Z_{NO} + \frac{Z_{BO}Z_{NO}}{Z_{AO}}$$

$$= 0.45 + 18.85 + \frac{0.45 \times 18.85}{0.75} = 30.6 \text{ ohms}$$

$$Z_{AB} = Z_{AO} + Z_{BO} + \frac{Z_{AO}Z_{BO}}{Z_{NO}}$$

$$= 1.2 \Omega \text{ since } Z_{NO} \gg Z_{AO}Z_{BO}$$

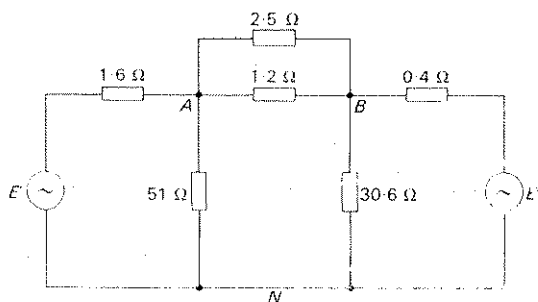
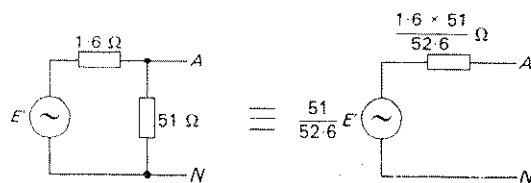
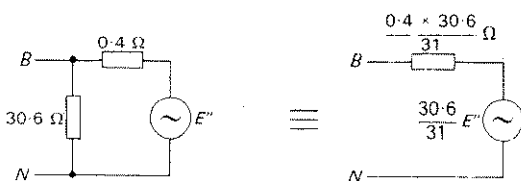


Figure 2.11 Reduction of passive branches by Kennelly's star/delta transformation.



(a) REDUCTION OF LEFT ACTIVE MESH



(b) REDUCTION OF RIGHT ACTIVE MESH

Figure 2.12 Reduction of active meshes by Thévenin's theorem.

The network is now reduced as shown in Figure 2.11.

By applying Thévenin's theorem to the active loops, these can be replaced by a single driving voltage in series with an impedance as shown in Figure 2.12.

The network shown in Figure 2.10 is now reduced to that shown in Figure 2.13 with the nodes *A* and *B* retaining their identity. Further, the load impedance has been completely eliminated.

The network shown in Figure 2.13 may now be used to study system disturbances, for example power swings with and without faults.

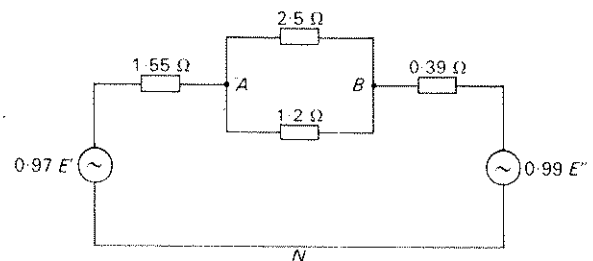


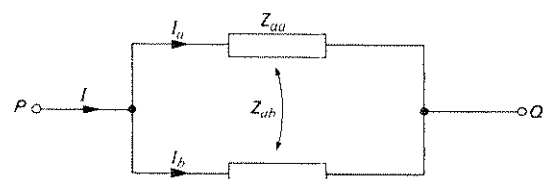
Figure 2.13 Reduction of typical power system network.

Most reduction problems follow the same pattern as the example above. If the system is complicated or the information required is extensive, leading to a great number of routine calculations, it is advisable to use a network analyzer.

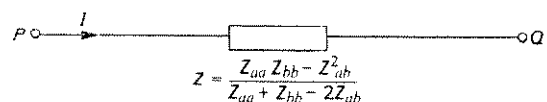
The rules to apply in practical network reduction are:

- Decide on the nature of the disturbance or disturbances to be studied.
- Decide on the information required, for example the branch currents in the network for a fault at a particular location.
- Reduce all passive sections of the network not directly involved with the section under examination.
- Reduce all active meshes to a simple equivalent, that is, to a simple source in series with a single impedance.

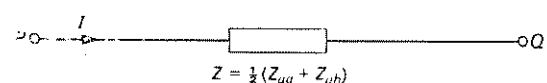
In certain circuits, for example parallel lines on the same towers, there is mutual coupling between branches. Correct circuit reduction must take account of this coupling.



(a) ACTUAL CIRCUIT



(b) EQUIVALENT WHEN  $Z_{aa} \neq Z_{bb}$



(c) EQUIVALENT WHEN  $Z_{aa} = Z_{bb}$

Figure 2.14 Reduction for two branches connected together at their nodes with mutual coupling between them.

Three cases are of interest. These are:

- Two branches connected together at their nodes.
- Two branches connected together at one node only.
- Two branches which remain unconnected.

Considering each case in turn:

a. Consider the circuit shown in Figure 2.14(a).

The application of a voltage  $V$  between the terminals,  $P$  and  $Q$  gives

$$V = I_a Z_{aa} - I_b Z_{ab}$$

$$V = I_b Z_{ba} - I_a Z_{ab}$$

where  $I_a$  and  $I_b$  are the currents in branches  $a$  and  $b$ , respectively, and  $I = I_a + I_b$ , the total current entering at terminal  $P$  and leaving at terminal  $Q$ .

Solving for  $I_a$  and  $I_b$ :

$$I_a = \frac{Z_{ba} - Z_{ab}}{Z_{aa} Z_{bb} - Z_{ab}^2} V$$

and which

$$I_b = \frac{Z_{aa} - Z_{ab}}{Z_{aa} Z_{bb} - Z_{ab}^2} V$$

and

$$I = I_a + I_b = \frac{V(Z_{aa} + Z_{bb} - 2Z_{ab})}{Z_{aa} Z_{bb} - Z_{ab}^2}$$

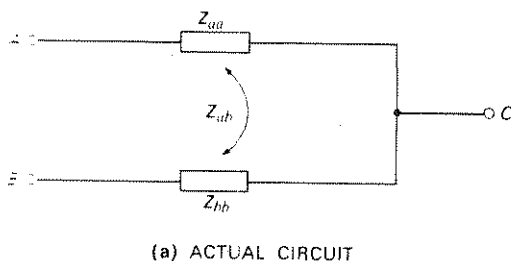
so that the equivalent impedance of the original circuit is:

$$Z = \frac{V}{I} = \frac{Z_{aa} Z_{bb} - Z_{ab}^2}{Z_{aa} + Z_{bb} - 2Z_{ab}} \quad \dots \text{Equation 2.23}$$

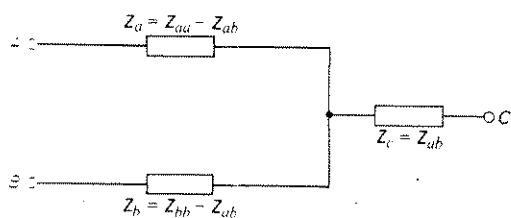
and if the branch impedances are equal, the usual case, then

$$Z = (Z_{aa} - Z_{ab}) \quad \dots \text{Equation 2.24}$$

b. Consider the circuit in Figure 2.15(a).



(a) ACTUAL CIRCUIT



(b) EQUIVALENT CIRCUIT

Figure 2.15 Reduction for two branches mutually coupled and connected at one terminal.

The assumption is made that the network can be replaced by an equivalent star. From inspection with one terminal isolated in turn and a voltage  $V$  impressed across the remaining terminals it can be seen that:

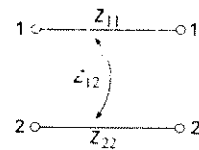
$$Z - Z = Z_{aa}$$

$$Z - Z = Z_{bb}$$

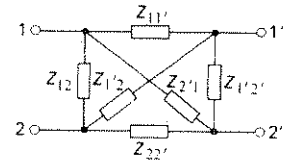
$$Z - Z = Z_{aa} + Z_{bb} - 2Z_{ab}$$

Solving these equations gives:

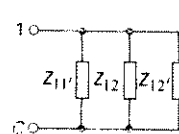
$$\left. \begin{aligned} Z_a &= Z_{aa} - Z_{ab} \\ Z_b &= Z_{bb} - Z_{ab} \\ Z_c &= Z_{ab} \end{aligned} \right\} \quad \dots \text{Equation 2.25}$$



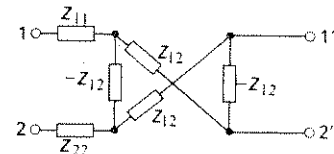
(a) ACTUAL CIRCUIT



(b) EQUIVALENT CIRCUIT



(c) EQUIVALENT WITH ALL NODES COMMONED EXCEPT 1



(d) EQUIVALENT CIRCUIT

Figure 2.16 Equivalent circuit for a four terminal network in which the branches are electrically separate except for mutual coupling.

c. Consider the four-terminal network given in Figure 2.16(a), in which the branches 11' and 22' are electrically separate except for a mutual link. The equations defining the network are:

$$V_1 = Z_{11} I_1 + Z_{12} I_2$$

$$V_2 = Z_{21} I_1 + Z_{22} I_2$$

$$I_1 = Y_{11} V_1 + Y_{12} V_2$$

$$I_2 = Y_{21} V_1 + Y_{22} V_2$$

where  $Z_{12} = Z_{21}$  and  $Y_{12} = Y_{21}$ , if the network is assumed to be reciprocal. Further, by solving the above equations it can be shown that:

$$Y_{11} = Z_{22}/\Delta$$

$$Y_{22} = Z_{11}/\Delta$$

$$Y_{12} = Z_{12}/\Delta$$

$$\Delta = Z_{11} Z_{22} - Z_{12}^2$$

$$\dots \text{Equation 2.26}$$

There are three independent co-efficients, namely  $Z_{12}$ ,  $Z_{11}$ ,  $Z_{22}$ , so the original circuit may be replaced by an equivalent mesh containing four external terminals, each terminal being connected to the other three by branch impedances as shown in Figure 2.16(b).

In order to evaluate the branches of the equivalent mesh let all points of entry of the actual circuit be commoned except node 1 of circuit 1, as shown in Figure 2.16(c). Then all impressed voltages except  $V_1$  will be zero and:

$$I_1 = Y_{11} V_1$$

$$I_2 = Y_{12} V_1$$

If the same conditions are applied to the equivalent mesh, then:

$$I_1 = V_1/Z_{11'}$$

$$I_2 = -V_1/Z_{12} = V_1/Z_{12'}$$

These relations follow from the fact that the branch connecting nodes 1 and 1' carries current  $I_1$ , and the branches connecting nodes 1 and 2' and 1 and 2 carry current  $I_2$ . This must be true since branches between pairs of commoned nodes can carry no current.

By considering each node in turn with the remainder commoned the following relationships are found:

$$Z_{11} = 1/Y_{11}$$

$$Z_{22} = 1/Y_{22}$$

$$Z_{12} = -\frac{1}{Y_{12}}$$

$$Z_{12} = Z_{21} = -Z_{21} = -Z_{12}$$

Hence:

$$\left. \begin{aligned} Z_{11} &= \frac{Z_{11}Z_{22} - Z_{12}^2}{Z_{22}} \\ Z_{22} &= \frac{Z_{11}Z_{22} - Z_{12}^2}{Z_{11}} \\ Z_{12} &= \frac{Z_{11}Z_{22} - Z_{12}^2}{Z_{12}} \end{aligned} \right\} \dots \text{Equation 2.27}$$

A similar but equally rigorous equivalent circuit is shown in Figure 2.16(d). This circuit follows from the reasoning that since the self impedance of any circuit is independent of all other circuits it need not appear in any of the mutual branches if it is lumped as a radial branch at the terminals. So putting  $Z_{11}$  and  $Z_{22}$  equal to zero in Equation 2.27, defining the equivalent mesh in Figure 2.16(b), and inserting radial branches having impedances equal to  $Z_{11}$  and  $Z_{22}$  in terminals 1 and 2, results in Figure 2.16(d).

## 2.7

Three-phase faults are unique in that they are balanced, that is, symmetrical in the three phases, and can be calculated from the single-phase impedance diagram and the operating conditions existing prior to the fault.

A fault condition is a sudden alteration in the normal circuit arrangement. The circuit quantities, current and voltage, will alter, and the circuit will pass through a transient state to a steady state. In the transient state, the initial magnitude of the fault current will depend upon the point on the voltage wave at which the fault occurs. The decay of the transient condition, until it merges into steady state, is a function of the parameters of the circuit elements. The transient current may be regarded as a d.c. exponential current superimposed on the symmetrical steady state fault current. In a.c. machines, owing to armature reaction, the machine reactances do not immediately assume their steady state synchronous value but pass through 'sub-transient' and 'transient' stages. For this reason, the resulting fault current during the transient period, from fault inception to steady state, also depends on the position of the fault in the network with respect to rotating plant.

In a system containing many voltage sources, or having a complex network arrangement, it is tedious to use the

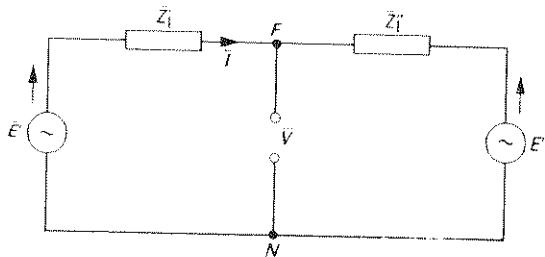


Figure 2.17 Simple system with a fault at F

normal system voltage sources to evaluate the fault current in the faulty branch or to calculate the fault current distribution in the system. A more practical method† is to replace the system voltages by a single driving voltage at the fault point. This driving voltage is the voltage existing at the fault point before the fault occurs.

Consider the circuit given in Figure 2.17 where the driving voltages are  $E'$  and  $E''$ , the impedances on either side of fault point F are  $Z_1$  and  $Z_2$ , and the current through point F before the fault occurs is  $I$ . The voltage  $V$  at F before fault inception is:

$$V = E' - IZ_1 = E'' + IZ_2$$

After the fault the voltage  $V$  is zero. Hence, the change in voltage is  $-V$ . Because of the fault the change in the current flowing into the network from F is:

$$\Delta I = -\frac{V}{Z_1} = -V \frac{(Z_1 + Z_2)}{Z_1 Z_2}$$

and, since no current was flowing into the network from F prior to the fault, the fault current flowing from the network into the fault is:

$$I_f = -\Delta I = V \frac{(Z_1 + Z_2)}{Z_1 Z_2} \dots \text{Equation 2.28}$$

By applying the principle of superposition, the load currents circulating in the system prior to the fault may be added to the currents circulating in the system due to the fault, to give the total current in any branch of the system at the time of fault inception. However, in most problems the load current is small in comparison to the fault current and is usually ignored.

In a practical power system the system regulation is such that the load voltage at any point in the system is within 10% of the declared open-circuit voltage at that point. For this reason, it is usual to regard the pre-fault voltage at the fault as being the open-circuit voltage.

For an example of practical three-phase fault calculations, consider a fault at A in Figure 2.10. With the network reduced as shown in Figure 2.13, the load voltage at A before the fault occurs is:

$$V = 0.97E' - 1.55I$$

$$V = 0.99E'' + \left( \frac{1.2 \times 2.5}{2.5 + 1.2} + 0.39 \right) I$$

For practical working conditions,  $E' \gg 1.55I$  and  $E'' \gg 1.207I$ . Hence,  $E' \approx E'' \approx V$ . Replacing the driving voltages  $E'$  and  $E''$  by the load voltage  $V$  between A and N modifies the circuit as shown in Figure 2.18(a).

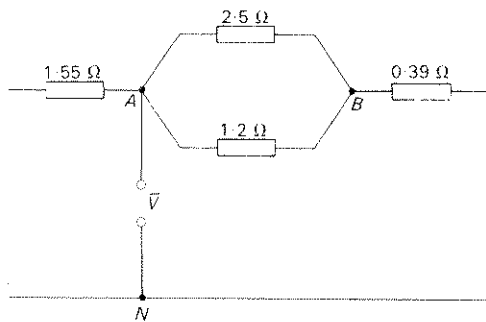
The node A is the junction of three branches. In practice the node would be a busbar, and the branches, feeders radiating from the bus via circuit breakers, as shown in Figure 2.18(b). There are two possible locations for a fault at A; the busbar side of the breakers or the line side of the breakers. In this example it is assumed that the fault is at X, and it is required to calculate the current flowing from the bus to X.

The network viewed from AN has a driving point impedance  $|Z_1| = 0.68$  ohms. The current in the fault is  $\left| \frac{V}{Z_1} \right|$ .

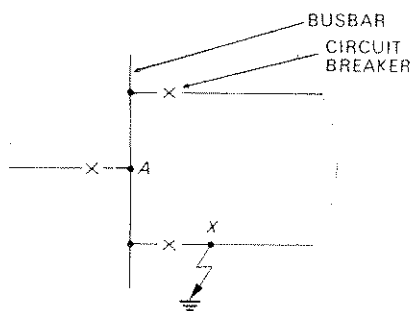
Let this current be 1.0 per unit. It is now necessary to find the fault current distribution in the various branches of the network and in particular the current flowing from A to X on the assumption that a relay at X is to detect the fault condition. The equivalent impedances viewed from either side of the fault are shown in Figure 2.19(a).

\* *Equivalent Circuits I*, Frank M. Starr, Proc. A.I.E.E. Vol. 51, 1932, pp. 287-298.

† *Circuit Analysis of A.C. Power Systems*, Volume I, Edith Clarke, John Wiley & Sons.

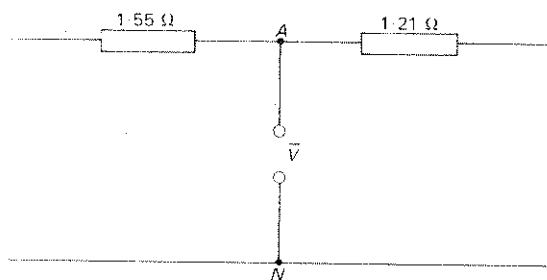


(a) THREE-PHASE FAULT DIAGRAM FOR A FAULT AT NODE A

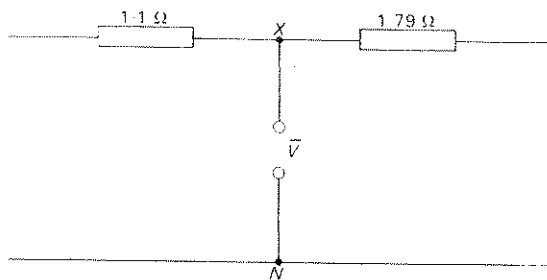


(b) TYPICAL PHYSICAL ARRANGEMENT OF NODE A WITH A FAULT SHOWN AT X

Figure 2.18 Typical power system with a fault at node A.



(a) IMPEDANCE VIEWED FROM NODE A



(b) EQUIVALENT IMPEDANCES VIEWED FROM NODE X

Figure 2.19 Impedances viewed from fault.

The currents from Figure 2.19(a) are as follows:

$$\text{From the right } \frac{1.55}{2.76} = 0.563 \text{ p.u.}$$

$$\text{From the left } \frac{1.21}{2.76} = 0.437 \text{ p.u.}$$

There is a parallel branch to the right of A.

Therefore, current in 2.5 ohm branch

$$= \frac{1.2 \times 0.563}{3.7} = 0.183 \text{ p.u.}$$

and current in 1.2 ohm branch

$$= \frac{2.5 \times 0.563}{3.7} = 0.38 \text{ p.u.}$$

Total current entering X from the left, that is, from A to X, is  $0.437 + 0.183 = 0.62 \text{ p.u.}$  and from B to X is  $0.38 \text{ p.u.}$  The equivalent network as viewed from the relay is as shown in Figure 2.19(b). The impedances on either side are:

$$0.68/0.62 = 1.1 \text{ ohms}$$

and

$$0.68/0.38 = 1.79 \text{ ohms}$$

The circuit of Figure 2.19(b) has been included because the protection engineer is interested in these equivalent parameters when applying certain types of protective relay.



# Fault calculations

3.1  
3.2  
3.3  
3.4  
3.5

## 3.1

A power system is normally treated as a balanced three-phase network. In general, when a fault occurs, the symmetry of a balanced network is upset, resulting in unbalanced currents and voltages appearing in the network. The exception to this rule is the three-phase fault, which, because it involves all three phases equally at the same location, is described as a symmetrical fault. By using symmetrical component theory and employing the concept of replacing the normal system sources by a source at the point of fault it is possible to analyze these fault conditions.

From the protective gear application point of view it is essential to know the fault current distribution through the system and the voltages in different parts of the system due to the fault. Further, boundary values of current at any relaying point must be known if the fault is to be cleared with discrimination. The information normally required is:

- i. Maximum fault current for a fault at the relaying point.
- ii. Minimum fault current for a fault at the relaying point.
- iii. Maximum through fault current at the relaying point.

To obtain the above information the limits of stable generation and possible operating conditions including the method of system earthing must be known, and the faults are always assumed to be through zero fault impedance.

## 3.2

It can be shown\* that, by applying the 'Principle of Superposition', any general three-phase system of vectors may be replaced by three sets of balanced (symmetrical) vectors; two sets are three-phase but having opposite phase rotation and one set is co-phasal. These vector sets are described as positive, negative and zero sequence sets respectively.

The equations between phase and sequence quantities are given below:

$$\left. \begin{aligned} \bar{E}_a &= \bar{E}_1 + \bar{E}_2 + \bar{E}_0 \\ \bar{E}_b &= a^2 \bar{E}_1 + a \bar{E}_2 + \bar{E}_0 \\ \bar{E}_c &= a \bar{E}_1 + a^2 \bar{E}_2 + \bar{E}_0 \end{aligned} \right\} \dots \text{Equation 3.1}$$

$$\left. \begin{aligned} \bar{E}_1 &= \frac{1}{3}(\bar{E}_a + a \bar{E}_b + a^2 \bar{E}_c) \\ \bar{E}_2 &= \frac{1}{3}(\bar{E}_a + a^2 \bar{E}_b + a \bar{E}_c) \\ \bar{E}_0 &= \frac{1}{3}(\bar{E}_a + \bar{E}_b + \bar{E}_c) \end{aligned} \right\} \dots \text{Equation 3.2}$$

where all quantities are referred to the reference phase A. A similar set of equations can be written for phase and sequence currents. Figure 3.1 illustrates the resolution of a system of unbalanced vectors.

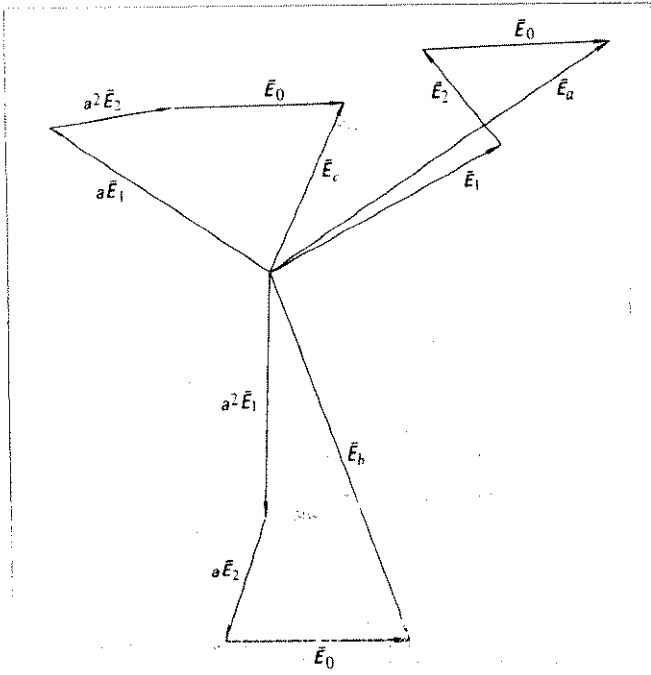


Figure 3.1 Resolution of a system of unbalanced vectors.

When a fault occurs in a power system, the phase impedances are no longer identical (except in the case of three-phase faults) and the resulting currents and voltages are unbalanced, the point of greatest unbalance being at the fault point. It has previously been shown that the fault may be studied by short-circuiting all normal driving voltages in the system and replacing the fault connection by a source whose driving voltage is equal to the pre-fault voltage at the fault point. Hence, the system impedances remain symmetrical, viewed from the fault, and the fault point may now be regarded as the point of injection of unbalanced voltages and currents into the system.

This is a most important approach in defining the fault conditions since it allows the system to be represented by sequence networks† using the method of symmetrical components.

The networks are described as positive, negative and zero sequence networks and only the appropriate sequence currents and voltages appear in them, there being no mutual connections whatsoever between the networks.

### 3.2.1

#### Positive sequence network

During normal system conditions only positive sequence currents and voltages can exist in the system, and therefore the normal system impedance network is a positive sequence network.

When a fault occurs the current in the fault branch changes from 0 to  $\bar{I}_1$  and the positive sequence voltage across the branch changes from  $\bar{V}$  to  $\bar{V}_1$ ; replacing the fault branch by a source equal to the change in voltage and short-circuiting all normal driving voltages in the system results in a current  $\Delta\bar{I}$  flowing into the system, and:

$$\Delta\bar{I} = -\frac{(\bar{V} - \bar{V}_1)}{\bar{Z}_1} \quad \dots \text{Equation 3.3}$$

where  $\bar{Z}_1$  is the positive sequence impedance of the system

\* *Method of Symmetrical Co-ordinates Applied to the Solution of Polyphase Networks*. C. L. Fortescue. A.I.E.E. Trans. Vol. 37, Part II 1918, pp. 1027-1140.

† *Power System Analysis*. J. R. Mortlock and M. W. Humphrey Davies, Chapman & Hall.

viewed from the fault. As before the fault no current was flowing from the fault into the system, it follows that  $\bar{I}_1$ , the fault current flowing from the system into the fault, must equal  $-\Delta\bar{I}$ . Therefore:

$$\bar{V}_1 = \bar{V} - \bar{I}_1\bar{Z}_1 \quad \dots \text{Equation 3.4}$$

is the relationship between positive sequence currents and voltages in the fault branch during a fault.

In Figure 3.2, which represents a simple system, the voltage drops  $\bar{I}_1\bar{Z}_1$  and  $\bar{I}_1'\bar{Z}_1'$  are equal to  $(\bar{V} - \bar{V}_1)$  where the rents  $\bar{I}_1$  and  $\bar{I}_1'$  enter the fault from the left and right respectively and impedances  $\bar{Z}_1$  and  $\bar{Z}_1'$  are the total system impedances viewed from either side of the fault branch. The voltage  $\bar{V}$  is usually equal to the open-circuit voltage in the system, and it has been shown that  $\bar{V} \approx \bar{E}' \approx \bar{E}''$  (see Section 2.7). So the positive sequence voltages in the system due to the fault are greatest at the source, as shown in the gradient diagram, Figure 3.2(b).

### 3.2.2

#### Negative sequence network

On the premise that only positive sequence quantities appear in a power system under normal conditions, then negative sequence quantities can exist only during an unbalanced fault.

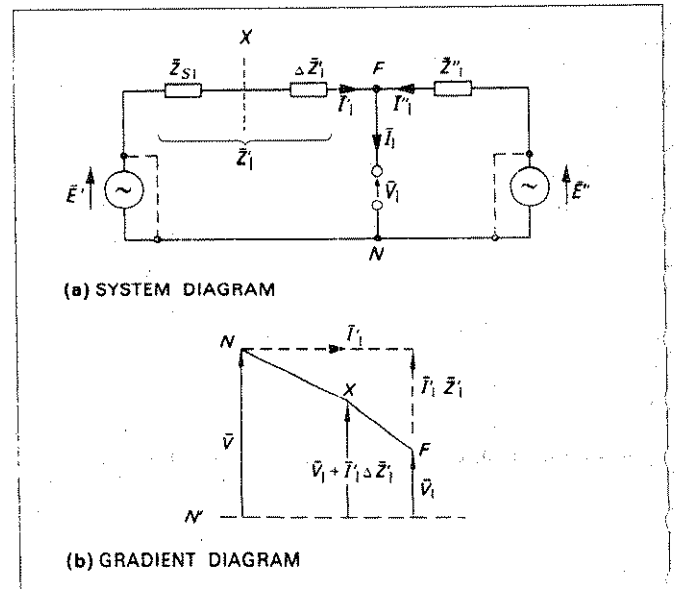


Figure 3.2 Positive sequence diagrams of a simple system with a fault at F.

If no negative sequence quantities are present in the fault branch prior to the fault, then, when a fault occurs, the change in voltage is  $\bar{V}_2$ , and the resulting current  $\bar{I}_2$  flowing from the network into the fault is:

$$\bar{I}_2 = \frac{-\bar{V}_2}{\bar{Z}_2}$$

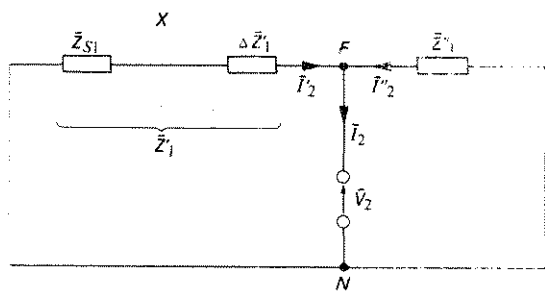
or

$$\bar{V}_2 = -\bar{I}_2\bar{Z}_2 \quad \dots \text{Equation 3.5}$$

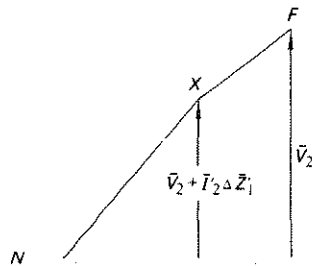
The impedances in the negative sequence network are generally the same as those in the positive sequence network. In machines  $\bar{Z}_1 \neq \bar{Z}_2$ , but the difference is generally ignored, particularly on large systems.

The negative sequence diagrams, shown in Figure 3.3, are similar to the positive sequence diagrams, with two important differences; no driving voltages exist before the fault, and the negative sequence voltage  $\bar{V}_2$  is greatest at the fault point





(a) NEGATIVE SEQUENCE NETWORK



(b) GRADIENT DIAGRAM

Figure 3.3 Negative sequence diagram of a simple system with a fault at F.

### 3.2.3

#### Zero sequence network

The same current and voltage relationships apply in the zero sequence network as in the negative sequence network during a fault condition. Hence:

$$\bar{I}_0 = -\bar{I}_2 \bar{Z}_0 \quad \dots \text{Equation 3.6}$$

Also, the zero sequence diagram is as shown in Figure 3.3 where  $\bar{I}_0$  is substituted for  $\bar{I}_2$ , and so on.

The currents and voltages in the zero sequence network are all in phase, that is, all the same phase. So for zero sequence currents to flow in a system there must be a return connection through either a neutral conductor or the general mass of earth. Note must be taken of this fact when determining zero sequence equivalent circuits. Further, in general  $\bar{Z}_1 \neq \bar{Z}_0$  and the value of  $\bar{Z}_0$  varies according to the type of plant, the winding arrangement and the method of earthing.

### 3.3

The most important types of faults are as follows:

- Single-phase-earth.
- Double-phase.
- Double-phase-earth.
- Three-phase (with or without earth).

The above faults are described as single shunt faults because they occur at one location and involve a connection between one phase and another or to earth.

By determining the currents and voltages at the fault point it is possible to define the fault and connect the sequence networks in such a manner as to represent the fault condition. From the initial equations and the network diagram it is then possible to determine the nature of the fault currents and voltages in different branches of the system.

Neglecting load current and assuming that the shunt faults listed above are through zero impedance, the equations defining each fault can be written down as follows:

- Single-phase-earth (A-E)

$$\left. \begin{aligned} I_b &= 0 \\ I_c &= 0 \\ V_a &= 0 \end{aligned} \right\} \quad \dots \text{Equation 3.7}$$

- Double-phase (B-C)

$$\left. \begin{aligned} I_a &= 0 \\ I_b &= -I_c \\ V_b &= V_c \end{aligned} \right\} \quad \dots \text{Equation 3.8}$$

- Double-phase-earth (B-C-E)

$$\left. \begin{aligned} I_a &= 0 \\ V_b &= 0 \\ V_c &= 0 \end{aligned} \right\} \quad \dots \text{Equation 3.9}$$

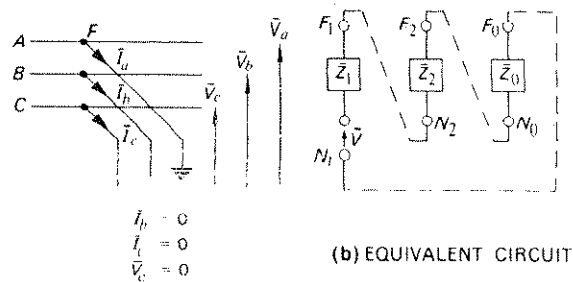
- Three-phase (A-B-C or A-B-C-E)

$$\left. \begin{aligned} I_a + I_b + I_c &= 0 \\ V_a &= V_b \\ V_b &= V_c \end{aligned} \right\} \quad \dots \text{Equation 3.10}$$

It should be noted from the above that for any type of fault there are three equations which define the fault conditions.

All currents and voltages are phase to neutral values at the fault point and it is assumed that no load current is flowing. When there is a fault impedance, this must be taken into account when writing down the equations. For example, with a single-phase earth fault through a fault impedance  $\bar{Z}_f$  Equations 3.7 are re-written:

$$\left. \begin{aligned} I_b &= 0 \\ I_c &= 0 \\ V_a &= I_a \bar{Z}_f \end{aligned} \right\} \quad \dots \text{Equation 3.11}$$



(a) DEFINITION OF FAULT



(b) EQUIVALENT CIRCUIT

Figure 3.4 Single-phase-earth fault (A-E).

### 3.3.1

#### Single-phase-earth fault (A-E)

Consider a fault defined by Equations 3.7 and by Figure 3.4(a). Converting Equations 3.7 into sequence quantities by using Equations 3.1 and 3.2, then:

$$\bar{I}_1 = \bar{I}_2 = \bar{I}_0 = \frac{1}{3} \bar{I}_a \quad \dots \text{Equation 3.12}$$

$$\bar{V}_1 = -(\bar{V}_2 + \bar{V}_0) \quad \dots \text{Equation 3.13}$$

Substituting for  $\bar{V}_1$ ,  $\bar{V}_2$  and  $\bar{V}_0$  in Equation 3.13 from Equations 3.4, 3.5 and 3.6:

$$\bar{V} - \bar{I}_1 \bar{Z}_1 = \bar{I}_2 \bar{Z}_2 + \bar{I}_0 \bar{Z}_0$$

but, from Equation 3.12,  $\bar{I}_1 = \bar{I}_2 = \bar{I}_0$ , therefore:

$$\bar{V} = \bar{I}_1 (\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_0) \quad \dots \text{Equation 3.14}$$

The constraints imposed by Equation 3.14 indicate that the equivalent circuit for the fault is obtained by connecting the sequence networks in series, as shown in Figure 3.4(b).

### 3.3.2

#### Double-phase fault (B-C)

From Equation 3.8 and using Equations 3.1 and 3.2:

$$\bar{I}_1 = -\bar{I}_2 \quad \dots \text{Equation 3.15}$$

$$\bar{I}_0 = 0$$

$$\bar{V}_1 = \bar{V}_2 \quad \dots \text{Equation 3.16}$$

From network Equations 3.4 and 3.5, Equation 3.16 can be re-written:

$$\bar{V} - \bar{I}_1 \bar{Z}_1 = -\bar{I}_2 \bar{Z}_2$$

and substituting for  $\bar{I}_2$  from Equation 3.15:

$$\bar{V} = \bar{I}_1 (\bar{Z}_1 + \bar{Z}_2) \quad \dots \text{Equation 3.17}$$

The constraints imposed by Equations 3.15 and 3.17 indicate that there is no zero sequence network connection in the equivalent circuit and that the positive and negative sequence networks are connected in parallel. Figure 3.5 shows the defining and equivalent circuits satisfying the above equations.

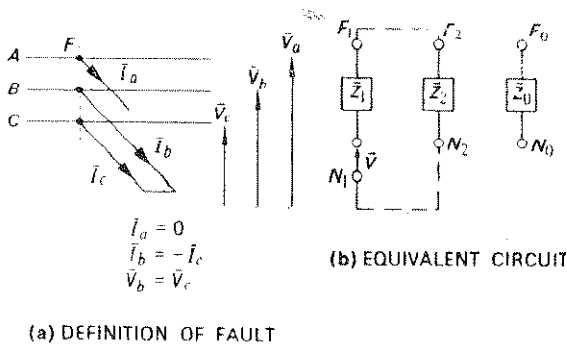


Figure 3.5 Double-phase fault (B-C).

### 3.3.3

#### Double-phase-earth fault (B-C-E)

Again, from Equation 3.9 and Equations 3.1 and 3.2:

$$\bar{I}_1 = -(\bar{I}_2 + \bar{I}_0) \quad \dots \text{Equation 3.18}$$

and

$$\bar{V}_1 = \bar{V}_2 = \bar{V}_0 \quad \dots \text{Equation 3.19}$$

Substituting for  $\bar{V}_2$  and  $\bar{V}_0$  using network Equations 3.5 and 3.6:

$$\bar{I}_2 \bar{Z}_2 = \bar{I}_0 \bar{Z}_0$$

Thus, using Equation 3.18:

$$\bar{I}_0 = -\frac{\bar{Z}_2 \bar{I}_1}{\bar{Z}_0 + \bar{Z}_2} \quad \dots \text{Equation 3.20}$$

$$\bar{I}_2 = -\frac{\bar{Z}_0 \bar{I}_1}{\bar{Z}_0 + \bar{Z}_2} \quad \dots \text{Equation 3.21}$$

Now, equating  $\bar{V}_1$  and  $\bar{V}_2$  and using Equation 3.4 gives:

$$\bar{V} - \bar{I}_1 \bar{Z}_1 = -\bar{I}_2 \bar{Z}_2$$

or

$$\bar{V} = \bar{I}_1 \bar{Z}_1 - \bar{I}_2 \bar{Z}_2$$

Substituting for  $\bar{I}_2$  from Equation 3.21:

$$\bar{V} = \left[ \bar{Z}_1 + \frac{\bar{Z}_0 \bar{Z}_2}{\bar{Z}_0 + \bar{Z}_2} \right] \bar{I}_1$$

or

$$\bar{I}_1 = \bar{V} \frac{(\bar{Z}_0 + \bar{Z}_2)}{\bar{Z}_1 \bar{Z}_0 + \bar{Z}_1 \bar{Z}_2 + \bar{Z}_0 \bar{Z}_2} \quad \dots \text{Equation 3.22}$$

From the above equations it follows that a double-phase earth fault may be represented by connecting the three sequence networks in parallel as shown in Figure 3.6(b).

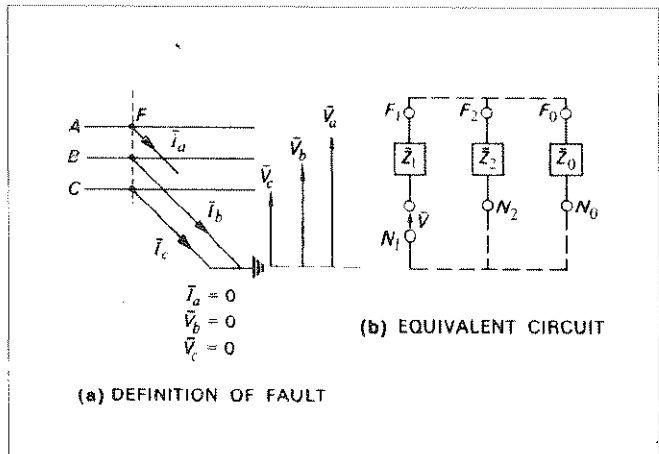


Figure 3.6 Double-phase-earth fault (B-C-E).

### 3.3.4

#### Three-phase fault (A-B-C or A-B-C-E)

Assuming that the fault includes earth, then, from Equations 3.10 and 3.1, 3.2, it follows that:

$$\left. \begin{aligned} \bar{V}_0 &= \bar{V}_a \\ \bar{V}_1 &= 0 \\ \bar{V}_2 &= 0 \end{aligned} \right\} \quad \dots \text{Equation 3.23}$$

and

$$\bar{I}_0 = 0 \quad \dots \text{Equation 3.24}$$

Substituting  $\bar{V}_2 = 0$  in Equation 3.5 gives:

$$\bar{I}_2 = 0 \quad \dots \text{Equation 3.25}$$

and substituting  $\bar{V}_1 = 0$  in Equation 3.4:

$$0 = \bar{V} - \bar{I}_1 \bar{Z}_1$$

or

$$\bar{V} = \bar{I}_1 \bar{Z}_1 \quad \dots \text{Equation 3.26}$$

Further, since from Equation 3.24  $\bar{I}_0 = 0$ , it follows from Equation 3.6 that  $\bar{V}_0$  is zero when  $\bar{Z}_0$  is finite. The equivalent sequence connections for a three-phase fault are shown in Figure 3.7.

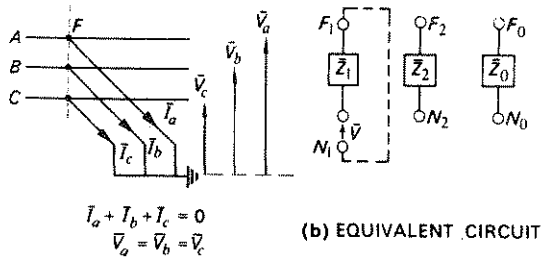
### 3.4

#### CURRENT AND VOLTAGE DISTRIBUTION IN A SYSTEM DUE TO A FAULT

Practical fault calculations involve the examination of the effect of a fault in branches of a network other than the fault branch, so that protection can be applied correctly to isolate the section of the system directly involved in the fault. It is therefore not enough to calculate the fault current in the fault itself; the fault current distribution must also be established. Further, abnormal voltage stresses may appear in a system because of a fault, and these may affect the operation of the protection. A knowledge of current and voltage distribution in a system due to a fault is essential for the application of protection.

The approach to system fault studies for assessing protective gear application may be summarized as follows:

a. From the system diagram and accompanying data assess the limits of stable generation and possible operating conditions for the system.



(a) DEFINITION OF FAULT

(b) EQUIVALENT CIRCUIT

Figure 3.7 Three-phase fault (A-B-C or A-B-C-E).

**NOTE:** When full information is not available assumptions may have to be made.

**b.** With faults assumed to occur at each relaying point in turn, maximum and minimum fault currents entering the fault are calculated for each type of fault.

**NOTE:** The fault is assumed to be through zero impedance.

**c.** By calculating the current distribution for faults at different points in the system (from (b) above) the maximum through fault currents at each relaying point are established for each type of fault.

**d.** At this stage more or less definite ideas on the type of protection to be applied are formed. Further calculations for establishing voltage variation at the relaying point, or the stability limit of the system with a fault on it, are now carried out in order to determine the class of protection necessary, such as high or low speed, unit or non-unit, and so forth.

### 3.4.1

#### Current distribution

The phase current in any branch of a network is determined from the sequence current distribution in the equivalent circuit for the fault. The sequence currents are expressed in per unit terms of the sequence current in the fault branch.

Since normally in power system calculations the positive sequence and negative sequence impedances are equal, the division of sequence currents in the two networks is identical.

The impedance values and configuration of the zero sequence network are usually different from those of the positive and negative sequence networks, so the zero sequence current distribution is calculated separately.

If  $C_0$  and  $C_1$  are described as zero and positive sequence distribution factors then the actual current in a sequence branch is given by multiplying the actual current in the sequence fault branch by the appropriate distribution factor. For this reason, if  $\bar{I}_1$ ,  $\bar{I}_2$  and  $\bar{I}_0$  are sequence currents in an arbitrary branch of a network due to a fault at some point in the network, then the phase currents in that branch may be expressed in terms of the distribution constants and the sequence currents in the fault. These are given below for the various common shunt faults, using Equation 3.1 and the appropriate fault equations:

**a. Single-phase-earth (A-E)**

$$\left. \begin{aligned} \bar{I}_1 &= (2C_1 + C_0) \bar{I}_0 \\ \bar{I}_2 &= -(C_1 - C_0) \bar{I}_0 \\ \bar{I}_0 &= -(C_1 - C_0) \bar{I}_0 \end{aligned} \right\} \dots \text{Equation 3.27}$$

**b. Double-phase (B-C)**

$$\left. \begin{aligned} \bar{I}_1 &= 0 \\ \bar{I}_2 &= (a^2 - a) C_1 \bar{I}_1 \\ \bar{I}_0 &= (a - a^2) C_1 \bar{I}_1 \end{aligned} \right\} \dots \text{Equation 3.28}$$

**c. Double-phase-earth (B-C-E)**

$$\left. \begin{aligned} \bar{I}_a &= -(C_1 - C_0) \bar{I}_0 \\ \bar{I}_b &= \left[ (a - a^2) C_1 \frac{\bar{Z}_0}{\bar{Z}_1} - a^2 C_1 + C_0 \right] \bar{I}_0 \\ \bar{I}_c &= \left[ (a^2 - a) C_1 \frac{\bar{Z}_0}{\bar{Z}_1} - a C_1 + C_0 \right] \bar{I}_0 \end{aligned} \right\} \dots \text{Equation 3.29}$$

**d. Three-phase (A-B-C or A-B-C-E)**

$$\left. \begin{aligned} \bar{I}_a &= C_1 \bar{I}_1 \\ \bar{I}_b &= a^2 C_1 \bar{I}_1 \\ \bar{I}_c &= a C_1 \bar{I}_1 \end{aligned} \right\} \dots \text{Equation 3.30}$$

As an example of current distribution technique, consider the system in Figure 3.8(a) and the equivalent sequence networks in Figure 3.8(b) and (c). A fault is assumed at A and it is desired to find the currents in branch OB due to the fault. In each network the distribution factors are given for each branch, with the current in the fault branch taken as 1.0 p.u. From the diagram the zero sequence distribution factor  $C_0$  in branch OB is 0.112 and the positive sequence factor  $C_1$  is 0.373. For an earth fault at A the phase currents in branch OB from Equation 3.27 are:

$$\begin{aligned} \bar{I}_a &= (0.746 + 0.112) \bar{I}_0 \\ &= 0.858 \bar{I}_0 \end{aligned}$$

and

$$\begin{aligned} \bar{I}_b &= \bar{I}_c = -(0.373 - 0.112) \bar{I}_0 \\ &= -0.261 \bar{I}_0 \end{aligned}$$

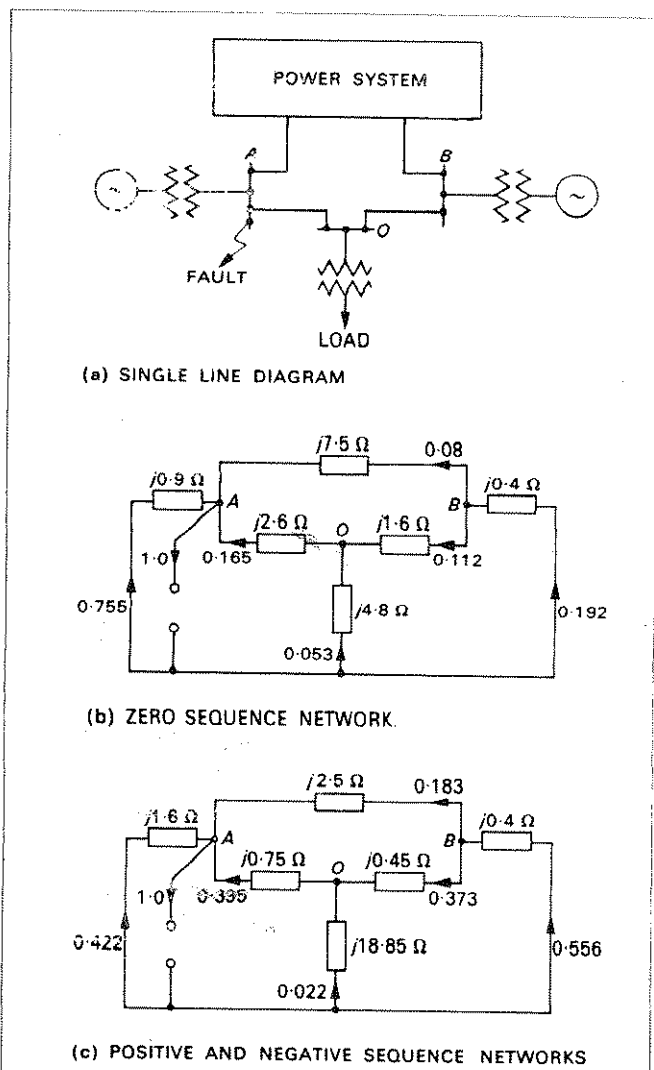


Figure 3.8 Typical power system.

By using network reduction methods and assuming that all impedances are reactive, it can be shown that  $\bar{Z}_1 = \bar{Z}_0 = j0.68$  ohms.

Therefore, from Equation 3.14, the current in fault branch  $|I_a| = |V|/0.68$ .

Assuming that  $|V| = 63.5$  volts, then:

$$|I_0| = \frac{1}{3} |I_a| = \frac{63.5}{3 \times 0.68} = 31.2 \text{ A}$$

If  $\bar{V}$  is taken as the reference vector, then:

$$\bar{I}'_a = 26.8 / -90^\circ \text{ A}$$

$$\bar{I}'_b = \bar{I}'_c = 8.15 / 90^\circ \text{ A}$$

The vector diagram for the above fault condition is shown in Figure 3.9.

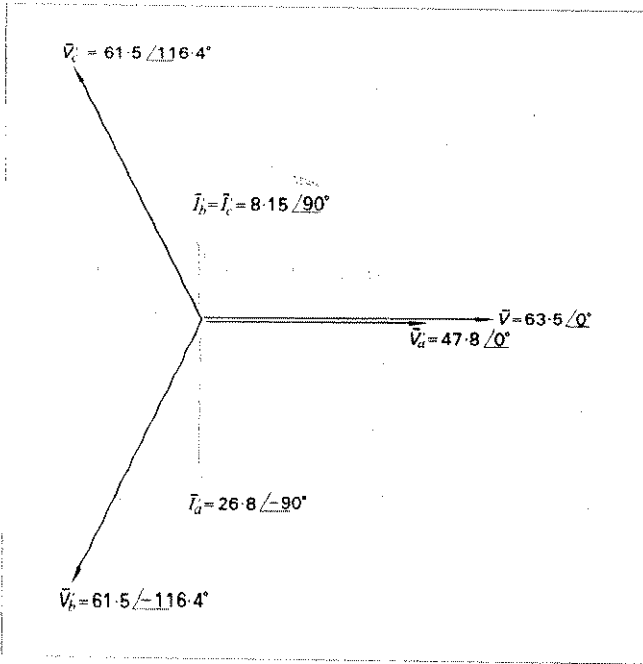


Figure 3.9 Vector diagram of fault currents and voltages in branch OB due to single-phase fault at bus A.

### 3.4.2 Voltage distribution

The voltage distribution in any branch of a network is determined from the sequence voltage distribution. As shown by Equations 3.4, 3.5 and 3.6 and the gradient diagrams, Figure 3.2(b) and 3.3(b), the positive sequence voltage is a minimum at the fault, whereas the zero and negative sequence voltages are a maximum. Thus, the sequence voltages in any part of the system may be given generally as:

$$\left. \begin{aligned} \bar{V}'_1 &= \bar{V} - \bar{I}_1 \left[ \bar{Z}_1 - \sum_1^n C_{1n} \Delta \bar{Z}_{1n} \right] \\ \bar{V}'_2 &= -\bar{I}_2 \left[ \bar{Z}_1 - \sum_1^n C_{1n} \Delta \bar{Z}_{1n} \right] \\ \bar{V}'_0 &= -\bar{I}_0 \left[ \bar{Z}_0 - \sum_1^n C_{0n} \Delta \bar{Z}_{0n} \right] \end{aligned} \right\} \dots \text{Equation 3.31}$$

Using the above equation the fault voltages at bus B in the previous example can be found.

From the positive sequence distribution diagram Figure 3.8(c):

$$\begin{aligned} \bar{V}'_1 &= \bar{V} - \bar{I}_1 [\bar{Z}_1 - j\{(0.395 \times 0.75) + (0.373 \times 0.45)\}] \\ &= \bar{V} - \bar{I}_1 [\bar{Z}_1 - j0.464] \end{aligned}$$

$$\bar{V}'_2 = -\bar{I}_2 [\bar{Z}_1 - j0.464]$$

From the zero sequence distribution diagram Figure 3.8(b):

$$\begin{aligned} \bar{V}'_0 &= \bar{I}_0 [\bar{Z}_0 - j\{(0.165 \times 2.6) + (0.112 \times 1.6)\}] \\ &= -\bar{I}_0 [\bar{Z}_0 - j0.608] \end{aligned}$$

For earth faults, at the fault  $\bar{I}_1 = \bar{I}_2 = \bar{I}_0 = -j31.2 \text{ A}$ , when  $|V| = 63.5$  volts and is taken as the reference vector. Further,  $\bar{Z}_1 = \bar{Z}_0 = j0.68$  ohms.

Hence:

$$\begin{aligned} \bar{V}'_1 &= 63.5 - (0.216 \times 31.2) \\ &= 56.76 / 0^\circ \text{ volts} \end{aligned}$$

$$\bar{V}'_2 = 6.74 / 180^\circ \text{ volts}$$

$$\bar{V}'_0 = 2.25 / 180^\circ \text{ volts}$$

and using Equations 3.1:

$$\begin{aligned} \bar{V}'_a &= \bar{V}'_1 + \bar{V}'_2 + \bar{V}'_0 \\ &= 56.76 - (6.74 + 2.25) \end{aligned}$$

$$\bar{V}'_a = 47.8 / 0^\circ \text{ volts}$$

$$\begin{aligned} \bar{V}'_b &= a^2 \bar{V}'_1 + a \bar{V}'_2 + \bar{V}'_0 \\ &= 56.76a^2 - (6.74a + 2.25) \end{aligned}$$

$$\bar{V}'_b = 61.5 / -116.4^\circ \text{ volts}$$

$$\begin{aligned} \bar{V}'_c &= a \bar{V}'_1 + a^2 \bar{V}'_2 + \bar{V}'_0 \\ &= 56.75a - (6.74a^2 + 2.25) \end{aligned}$$

$$\bar{V}'_c = 61.5 / 116.4^\circ \text{ volts}$$

These voltages are shown on vector diagram Figure 3.9.

## 3.5

### EFFECT OF SYSTEM EARTHING ON ZERO SEQUENCE QUANTITIES

It has been shown previously that zero sequence currents flow in the earth path during earth faults, and it follows that the nature of these currents will be influenced by the method of earthing. Because these quantities are unique in their association with earth faults they can be utilized in protection, provided their measurement and character are understood for all practical system conditions.

#### 3.5.1

##### Residual current and voltage

Residual currents and voltages depend for their existence on two factors:

- A system connection to earth at two or more points.
- A potential difference between the earthed points resulting in a current flow in the earth paths.

Under normal system operation there is capacitance between the phases and between phase and earth; these capacitances may be regarded as being symmetrical and distributed uniformly through the system. So even when (a) above is satisfied, if the driving voltages are symmetrical the vector sum of the currents will equate to zero and no current will flow between any two earth points in the system. When a fault to earth occurs in a system an unbalance results in condition (b) being satisfied. From the definitions given above it follows that residual currents and voltages are the vector sum of phase currents and phase voltages respectively.

Hence:

$$\bar{I}_R = \bar{I}_a + \bar{I}_b + \bar{I}_c$$

and

$$\bar{V}_R = \bar{V}_{ae} + \bar{V}_{be} + \bar{V}_{ce}$$

...Equation 3.32

Also, from Equations 3.2:

$$\left. \begin{aligned} \bar{I}_R &= 3\bar{I}_0 \\ \bar{V}_R &= 3\bar{V}_0 \end{aligned} \right\} \dots \text{Equation 3.33}$$

It should be further noted that:

$$\left. \begin{aligned} \bar{V}_{an} &= \bar{V}_{an} + \bar{V}_{ne} \\ \bar{V}_{bn} &= \bar{V}_{bn} + \bar{V}_{ne} \\ \bar{V}_{cn} &= \bar{V}_{cn} + \bar{V}_{ne} \end{aligned} \right\} \dots \text{Equation 3.34}$$

Hence, if  $\bar{V}_{bn} = a^2 \bar{V}_{an}$ ,  $\bar{V}_{cn} = a \bar{V}_{an}$ , then:

$$\bar{V}_R = 3\bar{V}_{ne} \dots \text{Equation 3.35}$$

where  $\bar{V}_{ne}$  = neutral displacement voltage.

Measurements of residual quantities are made using current and voltage transformer connections as shown in Figure 3.10 and if relays are connected into the circuits in place of the ammeter and voltmeter it follows that earth faults in the system can be detected.

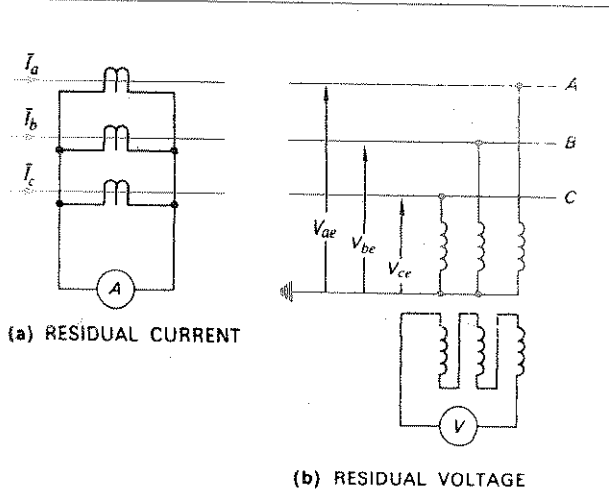


Figure 3.10 Measurement of residual quantities.

### 3.5.2

#### System $Z_0/Z_1$ ratio

The system  $Z_0/Z_1$  ratio is defined as the ratio of zero sequence and positive sequence impedances viewed from the fault; it is a variable ratio, dependent upon the method of earthing, fault position and system operating arrangement.

When assessing the distribution of residual quantities through a system it is convenient to use the fault point as the reference as it is the point of injection of unbalanced quantities into the system. The residual voltage is measured in relation to the normal phase-neutral system voltage and the residual current is compared with the three-phase fault current at the fault point. It can be shown\*† that the character of these quantities can be expressed in terms of the system  $Z_0/Z_1$  ratio.

The positive sequence impedance of a system is mainly reactive, whereas the zero sequence impedance being affected by the method of earthing may contain both resistive and reactive components of comparable magnitude. Thus the expression for the  $Z_0/Z_1$  ratio approximates to:

$$\frac{Z_0}{Z_1} = \frac{X_0}{X_1} - \frac{jR_0}{X_1} \dots \text{Equation 3.36}$$

Expressing the residual current in terms of the three-phase current and  $Z_0/Z_1$  ratio:

\* Neutral Groundings. R. Willheim and M. Waters, Elsevier.  
† Fault Calculations. C. H. W. Lackey, Oliver & Boyd.

#### a. Single-phase-earth (A-E)

$$\bar{I}_R = \frac{3\bar{V}}{2\bar{Z}_1 + \bar{Z}_0} = \frac{3}{(2 + \bar{K})} \frac{\bar{V}}{\bar{Z}_1}$$

where  $\bar{K} = \bar{Z}_0/\bar{Z}_1$

$$\bar{I}_{3\phi} = \frac{\bar{V}}{\bar{Z}_1}$$

Thus:

$$\frac{\bar{I}_R}{\bar{I}_{3\phi}} = \frac{3}{(2 + \bar{K})} \dots \text{Equation 3.37}$$

#### b. Double-phase-earth (B-C-E)

$$\bar{I}_R = 3\bar{I}_0 = -\frac{3\bar{Z}_1}{\bar{Z}_1 + \bar{Z}_0} \bar{I}_1$$

$$\bar{I}_1 = \frac{\bar{V}(\bar{Z}_1 + \bar{Z}_0)}{2\bar{Z}_1\bar{Z}_0 + \bar{Z}_1^2}$$

Hence:

$$\bar{I}_R = -\frac{3\bar{V}\bar{Z}_1}{2\bar{Z}_1\bar{Z}_0 + \bar{Z}_1^2} = -\frac{3}{(2\bar{K} + 1)} \frac{\bar{V}}{\bar{Z}_1}$$

Therefore:

$$\frac{\bar{I}_R}{\bar{I}_{3\phi}} = -\frac{3}{(2\bar{K} + 1)} \dots \text{Equation 3.38}$$

Similarly, the residual voltages are found by multiplying Equations 3.37 and 3.38 by  $-\bar{K}\bar{V}$ .

#### a. Single-phase-earth (A-E)

$$\bar{V}_R = -\frac{3\bar{K}}{(2 + \bar{K})} \bar{V} \dots \text{Equation 3.39}$$

#### b. Double-phase-earth (B-C-E)

$$\bar{V}_R = \frac{3\bar{K}}{(2\bar{K} + 1)} \bar{V} \dots \text{Equation 3.40}$$

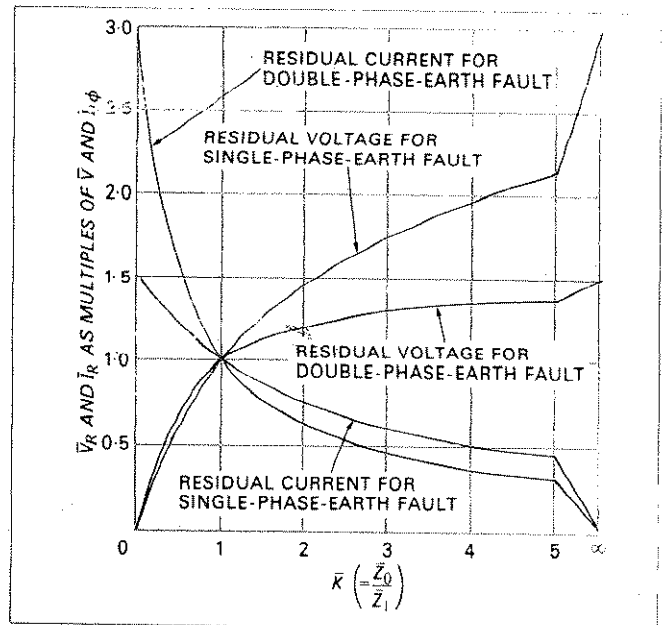


Figure 3.11 Variation of residual quantities at fault point.

The curves in Figure 3.11 illustrate the variation of the above residual quantities with the  $Z_0/Z_1$  ratio. The residual current in any part of the system can be obtained by multiplying the current from the curve by the appropriate zero sequence distribution factor. Similarly, the residual voltage is calculated by subtracting from the curve voltage three times the zero sequence voltage drop between the measuring point in the system and the fault.

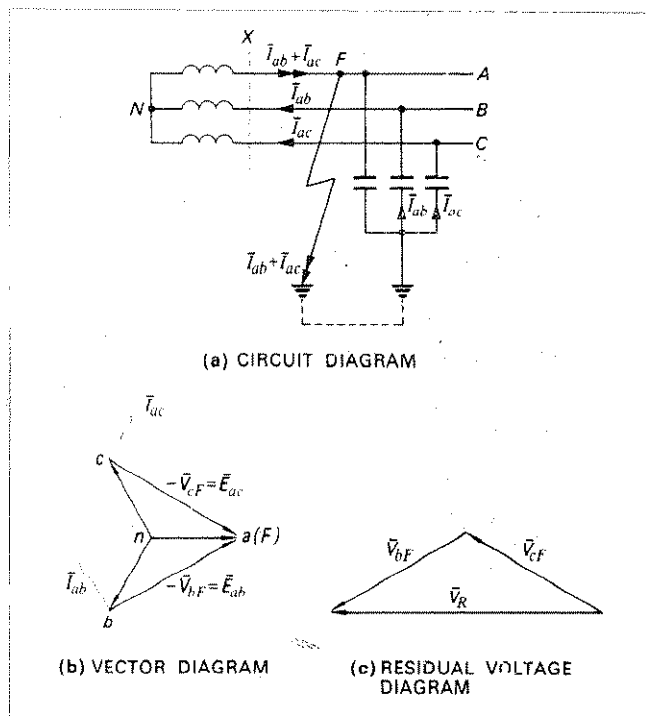


Figure 3.12 Solid fault-isolated neutral.

### 3.5.3

#### Variation of residual quantities

The variation of residual quantities in a system due to different earth arrangements can be most readily understood by using vector diagrams. Three examples have been chosen, namely solid fault-isolated neutral, solid fault-resistance neutral, and resistance fault-solid neutral. These are illustrated in Figures 3.12, 3.13 and 3.14 respectively.

##### a. Solid fault-isolated neutral.

From Figure 3.12 it can be seen that the capacitance to earth of the faulted phase is short circuited by the fault and the resulting unbalance causes capacitance currents to flow into the fault, returning via sound phases through sound phase capacitances to earth.

At fault:

$$\bar{V}_{aF} = 0$$

and

$$\begin{aligned}\bar{V}_R &= \bar{V}_{bF} + \bar{V}_{cF} \\ &= -3\bar{E}_{an}\end{aligned}$$

At source:

$$\bar{V}_R = 3\bar{V}_{nv} = -3\bar{E}_{an}$$

since

$$\bar{E}_{an} + \bar{E}_{bn} + \bar{E}_{cn} = 0$$

Thus, with an isolated neutral system, the residual voltage is three times the normal phase neutral voltage of the faulted phase and there is no variation between  $\bar{V}_R$  at source and  $\bar{V}_R$  at fault.

In practice there is some leakage impedance between neutral and earth and a small residual current would be detected at X if a very sensitive relay were employed.

##### b. Solid fault-resistance neutral.

Figure 3.13 shows that the capacitance of the faulted phase is short circuited by the fault and the neutral current combines with the sound phase capacitive currents to give  $\bar{I}_a$  in the faulted phase.

With a relay at X, residually connected as shown in Figure 3.10, the residual current will be  $\bar{I}_{an}$ , that is, the neutral-earth loop current.

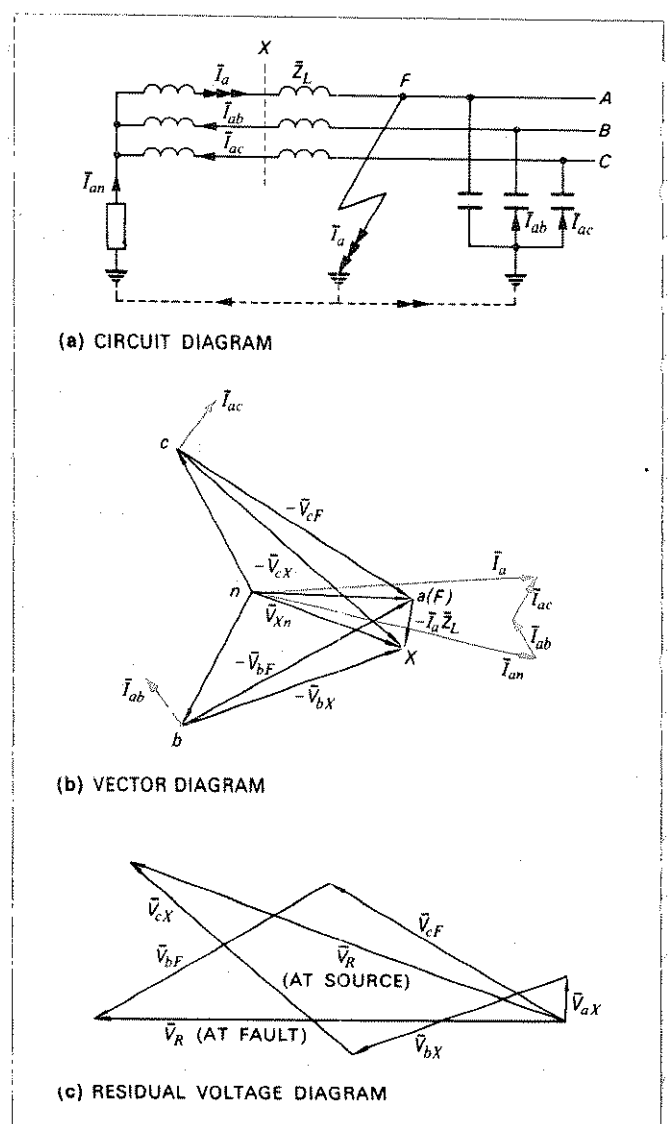


Figure 3.13 Solid fault-resistance neutral.

At fault:

$$\bar{V}_R = \bar{V}_{bF} + \bar{V}_{cF} \quad \text{since } \bar{V}_{Fe} = 0$$

At source:

$$\bar{V}_R = \bar{V}_{aX} + \bar{V}_{bX} + \bar{V}_{cX}$$

From the residual voltage diagram it is clear that there is little variation in the residual voltages at source and fault, as most residual voltage is dropped across the neutral resistor. The degree of variation in residual quantities is therefore dependent on the neutral resistor value.

##### c. Resistance fault-solid neutral.

Capacitance can be neglected because, since the capacitance of the faulted phase is not short-circuited, the circulating capacitance currents will be negligible.

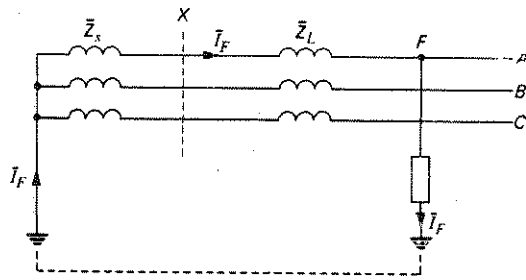
At fault:

$$\bar{V}_R = \bar{V}_{Fn} + \bar{V}_{bn} + \bar{V}_{cn}$$

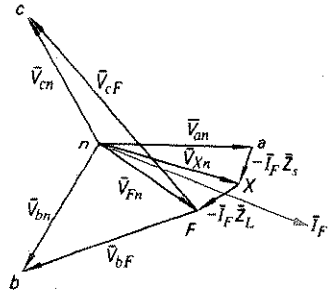
At relaying point X:

$$\bar{V}_R = \bar{V}_{Xn} + \bar{V}_{bn} + \bar{V}_{cn}$$

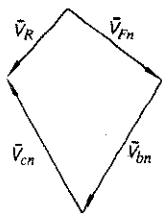
From the residual voltage diagrams, shown in Figure 3.14, it is apparent that the residual voltage is greatest at the fault and reduces towards the source. If the resistance in the fault approaches zero, that is, the fault becomes solid, then  $\bar{V}_{Fn}$  approaches zero and the voltage drops in  $\bar{Z}_S$  and  $\bar{Z}_L$  become greater. The ultimate value of  $\bar{V}_{Fn}$  will depend upon the effectiveness of the earthing, and this is a function of the system  $\bar{Z}_0/\bar{Z}_1$  ratio.



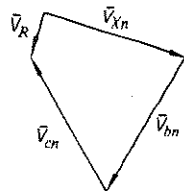
(a) CIRCUIT DIAGRAM



(b) VECTOR DIAGRAM



(c) RESIDUAL VOLTAGE AT FAULT



(d) RESIDUAL VOLTAGE AT RELAYING POINT

Figure 3.14 Resistance fault—solid neutral.





# Equivalent circuits and parameters of power system plant

- 4.1 Introduction
- 4.2 Synchronous machine
- 4.3 Armature reaction
- 4.4 Steady state theory
- 4.5 Saliency pole rotor
- 4.6 Transient analysis
- 4.7 Inductance
- 4.8 Inductive reactance
- 4.9 Inductive sequence reactance
- 4.10 Sequence reactance
- 4.11 Saliency pole rotor and its effect
- 4.12 Effect of saturation on machine reactance
- 4.13 Transformers
- 4.14 Inductive sequence equivalent circuit
- 4.15 Inductive equivalent circuit
- 4.16 Transformer
- 4.17 Overhead lines and cables
- 4.18 Calculation of series impedance
- 4.19 Calculation of shunt impedance
- 4.20 Overhead line circuits with or without earth
- 4.21 Inductor circuit
- 4.22 Inductor circuits
- 4.23 Inductor and cable lines

## 4.1

A knowledge of the behaviour of the principal units of system plant under normal and fault conditions is a prerequisite for the proper application of protective gear. This chapter summarizes basic synchronous machine, transformer and transmission theory and gives equivalent circuits and parameters so that a fault study can be successfully completed before the selection and application of the protective systems described in later chapters of this book. Power system plant may be divided into two broad groups; that which is rotating and that which is static. The problem with rotating plant is that its parameters change depending on its response to a change in power system conditions. With static plant this in general is not the case.

## 4.2

There are two main types of synchronous machine: cylindrical rotor and salient pole. In general, the former is confined to 2 and 4 pole turbine generators, while salient pole types are built from 4 poles upwards and include most classes of duty. Both classes of machine are basically similar in so far as each has a stator carrying a three-phase winding distributed over its inner periphery. Within the stator bore is carried the rotating member or rotor which is magnetized by a winding carrying d.c.

The essential difference between the two classes of machine lies in the rotor construction. The cylindrical rotor type has a uniformly cylindrical rotor which carries its excitation winding distributed over a number of slots around its periphery. This construction is unsuited to multi-polar machines but it is very sound mechanically. Hence it is particularly well adapted for the highest speed electrical machines and is universally employed for 2 pole units.

The salient pole type has poles which are physically separate, each carrying a concentrated excitation winding. This type of construction is in many ways complementary to that of the cylindrical rotor and is employed in machines having 4 poles or more. Except in special cases its use is exclusive in machines having more than 6 poles.

## 4.3

Armature reaction has the greatest effect on the operation of a synchronous machine with respect both to the load

angle at which it operates and to the amount of excitation that it needs. The phenomenon is most easily explained by considering a simplified ideal generator with full pitch winding operating at unity p.f., zero lag p.f. and zero lead p.f. When operating at unity p.f. the voltage and current in the stator are in phase, the stator current producing a cross magnetizing magneto-motive force (m.m.f.) which interacts with that of the rotor, resulting in a distortion of flux across the pole face. As can be seen from Figure 4.1(a) the tendency is to weaken the flux at the leading edge or effectively to distort the field in a manner equivalent to a shift against the direction of rotation.

If the power factor were reduced to zero lagging, the current in the stator would reach its maximum  $90^\circ$  after the voltage and the rotor would therefore be in the position shown in Figure 4.1(b). The stator m.m.f. is now acting in direct opposition to the field.

Similarly, for operation at zero leading power factor, the stator m.m.f. would directly assist the rotor m.m.f.

This m.m.f. arising from current flowing in the stator is known as 'armature reaction'.

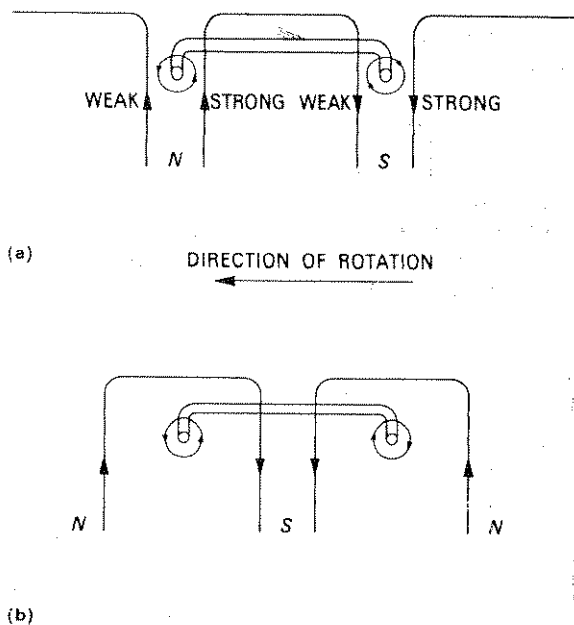


Figure 4.1 Distortion of flux due to armature reaction.

#### 4.4

The vector diagram of a single cylindrical rotor synchronous machine is shown in Figure 4.2, assuming that the magnetic circuit is unsaturated, the air-gap is uniform and all variable quantities are sinusoidal. Further, since the reactance of machines is normally very much larger than the resistance, the latter has been neglected.

The excitation ampere-turns,  $AT_e$ , produces a flux  $\Phi$  across the air-gap thereby inducing a voltage,  $E_i$ , in the stator. This voltage drives a current  $I$  at a power factor  $\cos^{-1} \phi$  and gives rise to an armature reaction m.m.f.  $AT_{ar}$  in phase with it. The m.m.f.  $AT_f$  resulting from the combination of these two m.m.f. vectors (see Figure 4.2(a)) is the actual excitation which must be provided on the rotor to maintain flux  $\Phi$  across the air-gap. Rotating the rotor m.m.f. diagram, Figure 4.2(a), anti-clockwise until  $AT_e$  coincides with  $E_i$  and changing the scale of the diagram so that  $AT_e$  becomes the basic unit, where  $AT_e = E_i = 1$ , results in Figure 4.2(b). The m.m.f. vectors have thus become, in effect, voltage vectors. For example,  $AT_{ar}/AT_e$  is a unit of voltage which is directly proportional to the stator load current. This vector can be fully represented by a reactance

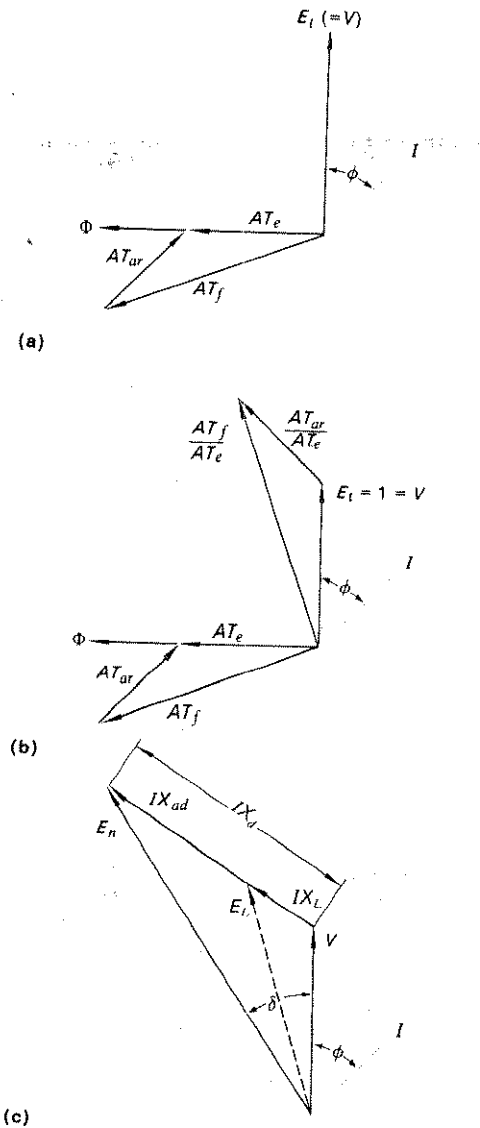


Figure 4.2 Vector diagram of synchronous machine.

and in practice this is called 'armature reaction reactance' and is denoted by  $X_{ad}$ . Similarly, the remaining side of the triangle becomes  $AT_f/AT_e$ , which is the per unit voltage produced on open circuit by ampere-turns  $AT_f$ . It can be considered as the internal generated voltage of the machine and is designated  $E_n$ .

The true leakage reactance of the stator winding which gives rise to a voltage drop or regulation has been neglected. This reactance is designated  $X_L$  and the voltage drop occurring in it,  $IX_L$ , is the difference between the terminal voltage  $V$  and the voltage behind the stator leakage reactance,  $E_L$ .

$IX_L$  will be exactly in phase with the voltage drop due to  $X_{ad}$ , as shown on the vector diagram Figure 4.2(c). It should be noted that  $X_{ad}$  and  $X_L$  can be combined to give a simple equivalent reactance; this is known as the 'synchronous reactance', denoted by  $X_d$ .

The power generated by the machine is given by the equation:

$$P = VI \cos \phi = \frac{VE_n}{X_d} \sin \delta \quad \dots \text{Equation 4.1}$$

where  $\delta$  is the angle between the internal voltage and the terminal voltage and is known as the load angle of the machine.

It follows from the above analysis that for steady state performance the machine may be represented by the

equivalent circuit shown in Figure 4.3 where  $X_L$  is a true reactance associated with flux leakage around the stator winding and  $X_{ad}$  is a fictitious reactance, being the ratio of armature reaction and open-circuit excitation magnetomotive forces.

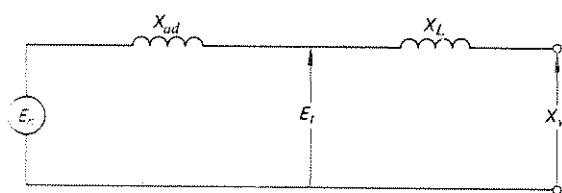


Figure 4.3 Equivalent circuit of machine.

#### 4.5

##### SALENT POLE MACHINE

The preceding theory is limited to the cylindrical rotor. In some cases this treatment is adequate for the salient pole rotor as well but there are some instances where this is not so. The differences arise because the basic assumption (that the air-gap is uniform) is very obviously not valid when a salient pole rotor is being considered. The effect of this is that the flux produced by armature reaction m.m.f. depends on the position of the rotor at any instant, as shown in Figure 4.4.

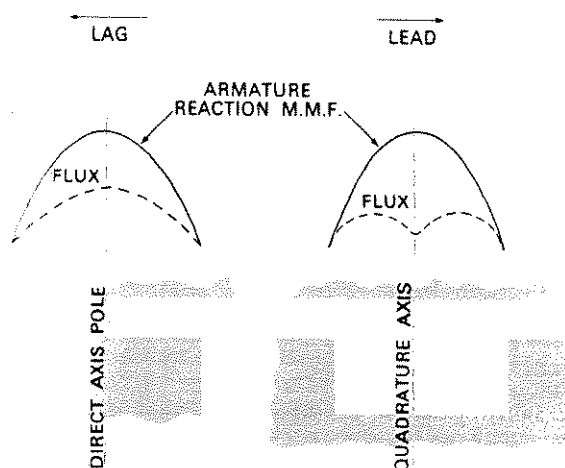


Figure 4.4 Variation of armature reaction m.m.f. with pole position.

When a pole is aligned with the assumed sine wave m.m.f. set up by the stator a corresponding sine wave flux will be set up, but when an inter-polar gap is aligned very severe distortion is caused. The difference is treated by considering these two axes, that is, those corresponding to the pole and the inter-polar gap, separately. They are designated the 'direct' and 'quadrature' axes respectively, and the general theory is known as the 'two axes' theory.

The vector diagram for the salient pole machine is similar to that for the cylindrical rotor except that the reactance and currents associated with them are split into two components. The synchronous reactance for the direct axis is  $X_d = X_{ad} + X_L$ , while that in the quadrature axis is  $X_q = X_{aq} + X_L$ . The vector diagram is constructed as before but the appropriate quantities in this case are resolved along two axes. The resultant internal voltage is  $E_n$ , as shown in Figure 4.5.

It should be noted that  $E_n$  is the internal voltage which would be given, in cylindrical rotor theory, by vectorially adding the simple vector  $IX_d$  and  $V$ . There is very little difference in magnitude between  $E_n$  and  $E_n$  but a

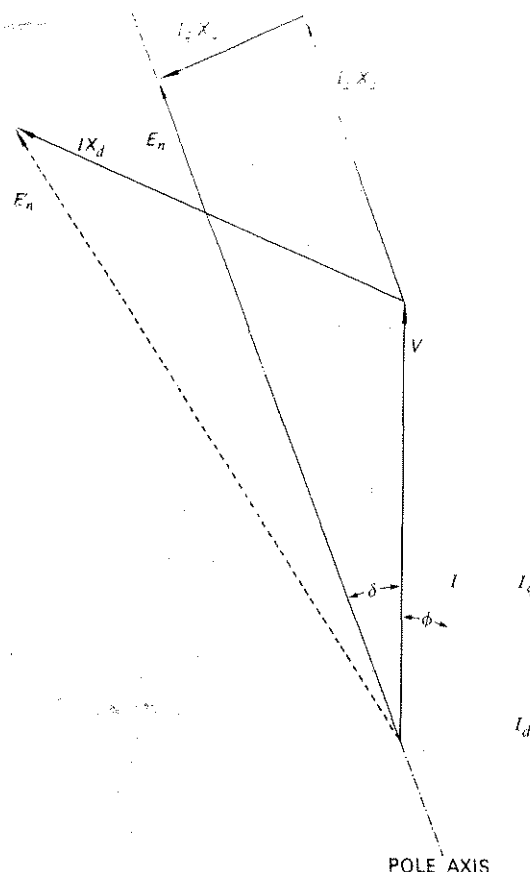


Figure 4.5 Vector diagram for salient pole machine.

substantial difference in internal angle; the simple theory is perfectly adequate for calculation of excitation currents but not for stability considerations where load angle is significant.

#### 4.6

For normal changes in load conditions, steady state theory is perfectly adequate. However, there are occasions when almost instantaneous changes are involved, such as faults or switching operations. When this happens new factors are introduced within the machine and to represent these adequately a corresponding new set of machine characteristics is required.

The generally accepted and most simple way to appreciate the meaning and derivation of these characteristics is to consider a sudden three-phase short circuit applied to a machine initially running on open circuit and excited to normal voltage  $E_n$ .

This voltage will be generated by a flux crossing the air-gap. Now, in no machine is it possible to confine the flux to one path exclusively, and as a result there will be a leakage flux  $\Phi_L$  which will leak from pole to pole and across the inter-polar gaps without crossing the main air-gap as shown in Figure 4.6. The flux in the pole will be  $\Phi + \Phi_L$ .

If the stator winding is then short-circuited the power factor in it will be zero and a heavy current will tend to flow, the resulting armature reaction m.m.f. being directly demagnetizing. This will reduce the flux and conditions will settle until the armature reaction nearly balances the excitation m.m.f., the remainder maintaining a very much reduced flux across the air-gap which is just sufficient to generate the voltage necessary to overcome the stator leakage reactance (resistance neglected). This is the simple steady state case of a machine operating on short circuit and is fully represented by the equivalent of Figure 4.7(a) see also Figure 4.3.

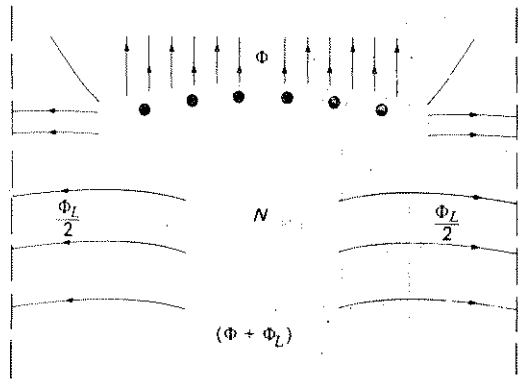


Figure 4.6 Flux paths of salient pole machine.

It might be expected that the fault current would be given by  $E_0/(X_L + X_{ad})$  equal to  $E_0/X_d$ , but this is very much reduced, and the machine is operating with no saturation. For this reason, the value of voltage used is the value read from the air-gap line corresponding to normal excitation and is rather higher than the normal voltage. The steady state current is given by:

$$I_d = \frac{\text{Voltage from air-gap line at normal open-circuit excitation}}{\text{Synchronous reactance } (X_d)} \quad \text{Equation 4.2}$$

An important point to note now is that between the initial and final conditions there has been a severe reduction of flux. The rotor carries a highly inductive winding which links the flux so that the rotor flux linkages before the short circuit are produced by  $(\Phi + \Phi_L)$ . In practice the leakage flux is distributed over the whole pole and all of it does not link all the winding.  $\Phi_L$  is an equivalent concentrated flux imagined to link all the winding and of such a magnitude that the total linkages are equal to those actually occurring. It is a fundamental principle that any attempt to change the flux linked with such a circuit will cause currents to flow in a direction which will oppose the change. In the present case the flux is being reduced and so the induced currents will tend to sustain it.

For the position immediately following the application of the short circuit it is valid to assume that the flux linked

with the rotor remains constant, this being brought about by an induced current in the rotor which balances the heavy demagnetizing effect set up by the short-circuited armature. So  $(\Phi + \Phi_L)$  remains constant, but owing to the increased m.m.f. involved, the flux leakage will increase considerably. With a constant total rotor flux this can only increase at the expense of that flux crossing the air-gap. Consequently, this generates a reduced voltage, which, acting on the leakage reactance  $X_L$ , gives the short circuit current.

It is more convenient for machine analysis to use the rated voltage  $E_0$  and to invent a fictitious reactance which will give rise to the same current. This reactance is called the 'transient reactance'  $X'_d$  and is defined by the equation:

$$\text{Transient current} = I'_d = \frac{\text{Rated voltage } (E_0)}{X'_d} \quad \text{Equation 4.3}$$

It is greater than  $X_L$ , and the equivalent circuit is represented by Figure 4.7(b) where:

$$X'_d = \frac{X_{ad}X_f}{X_{ad} + X_f} + X_L = X_L + X'_f$$

$X_f$  = leakage reactance of field winding.

$X'_f$  = effective leakage reactance of field winding.

The flux will only be sustained at its relatively high value while the induced current flows in the field winding. As this current decays so conditions will approach the steady state. Consequently, the duration of this phase will be determined by the time constant of the excitation winding. This is usually of the order of a second or less—hence the term 'transient' applied to characteristics associated with it.

A further point now arises. Under short circuit conditions there is a transfer of flux from the main air-gap to leakage paths. This diversion is, to a small extent, opposed by the excitation winding and the main transfer will be experienced towards the pole tips.

If a damper winding is carried in the pole face, this will be subjected to the full effect of flux transfer to leakage paths and will carry an induced current tending to oppose it. As long as this current can flow, the air-gap flux will be held at a value slightly higher than would be the case if only the excitation winding were present, but still less than the original open circuit flux  $\Phi$ .

As before, it is convenient to use rated voltage and to create another fictitious reactance which is considered to be effective over this period. This is known as the 'sub-transient reactance'  $X''_d$  and is defined by the equation:

$$\text{Sub-transient current} = I''_d = \frac{\text{Rated voltage } (E_0)}{X''_d} \quad \text{Equation 4.4}$$

It is greater than  $X_L$  but less than  $X'_d$  and the corresponding equivalent circuit is shown in Figure 4.7(c).

$$\text{where } X''_d = X_L + \frac{X_{ad}X_fX_{kd}}{X_{ad}X_f + X_{kd}X_f + X_{ad}X_{kd}}$$

$$\text{or } X''_d = X_L + X''_{kd}$$

$X_{kd}$  = leakage reactance of damper winding.

$X''_{kd}$  = effective leakage reactance of damper winding.

Again, the duration of this phase depends upon the time constant of the damper winding. In practice this is usually approximately 0.05 seconds—very much less than the transient—hence the term 'sub-transient'.

Figure 4.8 shows the envelope of the symmetrical component of an armature short circuit current indicating the values described in the preceding analysis. The sudden short circuit and its analysis thus is the method by which these reactances are measured.

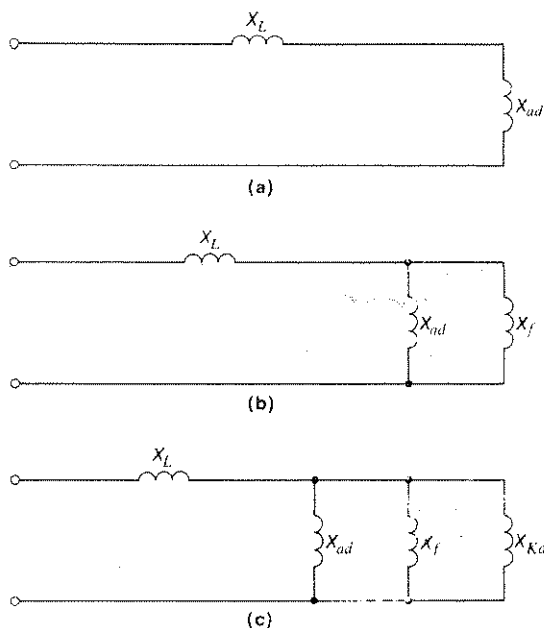


Figure 4.7 Machine reactances.

A detailed description of the procedure is set out in the I.E.E. Test Code for synchronous machines, Pub. No. 503.

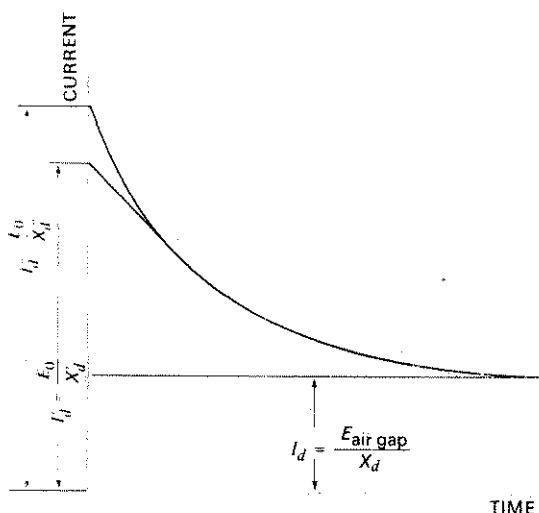


Figure 4.8 Transient decay envelope of short-circuit current.

#### 4.7

##### 4.7.1 The short circuit

The exact instant at which the short circuit is applied to the stator winding is of significance. If resistance is negligible compared with reactance, the current in a coil will lag the voltage by  $90^\circ$ , that is, at the instant when the voltage wave attains a maximum, any current flowing through would be passing through zero. If a short circuit were applied at this instant, the resulting current would rise smoothly and would be a simple a.c. component. However, at the moment when the induced voltage is zero, any current flowing must pass through a maximum (owing to the  $90^\circ$  lag). If a fault occurs at this moment the resulting current will assume the corresponding relationship; it will be at its peak and in the ensuing  $180^\circ$  will go through zero to maximum in the reverse direction and so on. In fact the current must actually start from zero and so will follow a sine wave which is completely asymmetrical. Intermediate positions will give varying degrees of asymmetry.

This asymmetry can be considered to be due to a d.c. component of current which dies away because resistance is present.

This d.c. component of stator current sets up a d.c. field which causes a 50 Hz ripple on the field current, and this alternating rotor flux has a further effect on the stator. This is best shown by considering the 50 Hz flux as being represented by two half magnitude waves each rotating in opposite directions at 50 Hz relative to the rotor. So, as viewed from the stator one is stationary and the other

rotating at 100 Hz. The latter sets up second harmonic currents in the stator. Further development along this line is possible but the resulting harmonics are negligible and normally neglected.

#### 4.8

Table 4.1 gives typical values of machine reactances for salient pole and cylindrical rotor machines.

##### 4.8.1

**Synchronous reactance**  $X_d = X_L + X_{ad}$

The order of  $X_L$  is normally 0.1–0.25 p.u. while that of  $X_{ad}$  is 1.0–2.5 p.u. The leakage reactance  $X_L$  can be reduced by increasing the machine size (derating), or increased by artificially increasing the slot leakage, but it will be noted that  $X_L$  is only about 10% of the total value of  $X_d$  and cannot exercise much influence.

The armature reaction reactance can be reduced by decreasing the armature reaction of the machine which in design terms means reducing the ampere conductor or electrical (as distinct from magnetic) loading—this will often mean a physically larger machine.

Alternatively the excitation needed to generate open-circuit voltage may be increased; this is simply achieved by increasing the machine air-gap, but is only possible if the excitation system is modified to meet the increased requirements.

In general, control of  $X_d$  is obtained almost entirely by varying  $X_{ad}$ , and in most cases a reduction in  $X_d$  will mean a larger and more costly machine. It is also worth noting that  $X_L$  normally changes in sympathy with  $X_{ad}$ , but that it is completely overshadowed by it.

The synchronous reactance is a measure of the steady state stability of the machine; the smaller its value the more stable the machine, as can be seen from the typical power chart, Figure 4.9.

The value  $1/X_d$  has a special significance as it approximates to the short circuit ratio (S.C.R.), the only difference being that the S.C.R. takes saturation into account whereas  $X_d$  is derived from the air-gap line.

##### 4.8.2

**Transient reactance**  $X_d' = X_L + X_d'$

Transient reactance covers the behaviour of a machine in the period 0.1–3.0 seconds after a disturbance. This generally corresponds to the speed of changes in a system and is usually employed in studies of transient stability.

Generally, the leakage reactance  $X_L$  is equal to the effective field leakage reactance  $X_f'$ , about 0.1–0.25 p.u. The principal factor determining the value of  $X_f'$  is the field leakage. This is largely beyond the control of the designer, in that other considerations are at present more significant than field leakage and hence take precedence in determining the field design.

| Type of machine                               |        | Salient pole synchronous condensers |           | Cylindrical rotor turbine generators |               | Salient pole generators |            |
|-----------------------------------------------|--------|-------------------------------------|-----------|--------------------------------------|---------------|-------------------------|------------|
|                                               |        |                                     |           | Conventional                         | Direct cooled | 4 Pole                  | Multi-pole |
| Short circuit ratio                           |        | 0.5–0.7                             | 1.0–1.2   | 0.5                                  | 0.5           | 0.5–0.9                 | 0.8        |
| Synchronous reactance — direct axis           | (p.u.) | 1.6–2.0                             | 0.8–1.0   | 2.0–2.3                              | 2.1–2.4       | 1.3–2.1                 | 1.3–1.5    |
| Synchronous reactance — quadrature axis       | (p.u.) | 1.0–1.25                            | 0.5–0.65  | 1.9–2.1                              | 1.95–2.25     | 0.6–1.2                 | 0.8–1.0    |
| Transient reactance                           | (p.u.) | 0.3–0.5                             | 0.2–0.35  | 0.18–0.25                            | 0.27–0.30     | 0.15–0.35               | 0.4–0.5    |
| Sub-transient reactance — direct axis         | (p.u.) | 0.2–0.4                             | 0.12–0.25 | 0.11–0.13                            | 0.19–0.23     | 0.1–0.25                | 0.2–0.35   |
| Sub-transient reactance — quadrature axis     | (p.u.) | 0.25–0.6                            | 0.15–0.45 |                                      |               | 0.14–0.35               |            |
| Negative sequence reactance                   | (p.u.) | 0.25–0.5                            | 0.14–0.35 | 0.05–0.075                           | 0.11–0.16     | 0.12–0.3                | 0.1–0.2    |
| Zero sequence reactance                       | (p.u.) | 0.12–0.16                           | 0.06–0.10 |                                      |               | 0.03–0.10               |            |
| Short circuit transient time constant         | (s)    | 1.5–2.5                             | 1.0–2.0   | 0.75–1.0                             | 0.75–1.0      | 0.8–1.2                 | 0.8–1.2    |
| Open circuit transient time constant          | (s)    | 5–10                                | 3–7       | 4–8                                  | 6–9.5         | 4–8                     | 3–7        |
| Short circuit sub-transient — direct axis     | (s)    | 0.04–0.09                           | 0.05–0.10 | 0.015–0.025                          | 0.02–0.03     | 0.02–0.04               | 0.02–0.07  |
| Short circuit sub-transient — direct axis     | (s)    | 0.07–0.11                           | 0.08–0.25 |                                      |               | 0.04–0.07               |            |
| Short circuit sub-transient — quadrature axis | (s)    | 0.04–0.6                            | 0.05–0.6  | 0.015–0.025                          | 0.02–0.03     | 0.10–0.15               | 0.1–0.2    |
| Open circuit sub-transient — quadrature axis  | (s)    | 0.1–1.2                             | 0.2–0.9   |                                      |               | 0.3–0.7                 |            |

Table 4.1 Typical values of machine characteristics

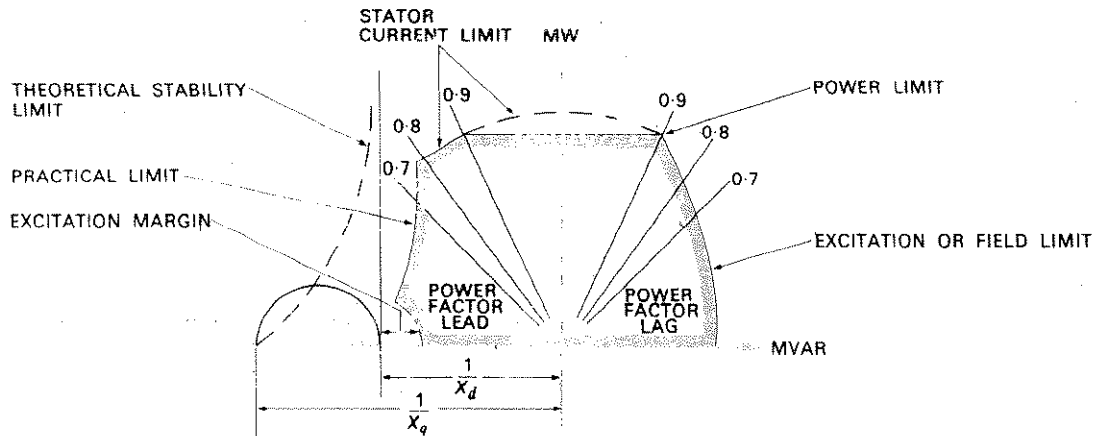


Figure 4.9 Typical operating power chart.

$X_L$  can be varied as already outlined, and, in practice, control of transient reactance is usually achieved by varying  $X_L$ .

#### 4.8.3

**Sub-transient reactance**  $X_d'' = X_L + X_{kd}'$

The sub-transient reactance determines the initial current peaks following a disturbance and in the case of a sudden fault is of importance for selecting the rupturing capacity of associated circuit breakers. The mechanical stresses on the machine reach maximum values which depend on this constant. The effective damper winding leakage reactance  $X_{kd}'$  is largely determined by the leakage of the damper windings and control of this is only possible to a limited extent.  $X_{kd}'$  can be expected to fall between 0.05 and 0.15 p.u. The major factor is  $X_L$  which, as indicated previously, is of the order of 0.1–0.25 p.u., and control of the sub-transient reactance is normally achieved by varying  $X_L$ .

#### 4.9

Negative sequence currents can arise whenever there is any unbalance present in the system. Their effect is to set up a field rotating in the opposite direction to the main field (that is, the rotor), so subjecting it to double frequency flux pulsations. This gives rise to parasitic currents and heating; most machines are quite limited in the amount of such current which they are able to carry.

It is almost impossible to calculate accurately how much negative sequence current can be carried since the current paths involved are very uncertain and widely distributed. In a turbine generator rotor, for instance, they include the solid rotor body, slot wedges, excitation winding and end-winding retaining rings. There is a tendency for local overheating to occur and, although possible for the stator, continuous local temperature measurement is not practicable here.

In practice an empirical method is used, based on the fact that a given type of machine is capable of carrying, for short periods, an amount of heat determined by its thermal capacity, and for long periods, a rate of heat input which it can dissipate. Synchronous machines are designed to be capable of operating continuously on an unbalanced system such that, with none of the phase currents exceeding the rated current, the ratio of the negative sequence current ( $I_2$ ) to the rated current ( $I_N$ ) does not exceed the values given in Table 4.2. Under fault conditions the machine shall also be capable of operation with the product of  $\left(\frac{I_2}{I_N}\right)^2$  and time in seconds ( $t$ ) not exceeding the values given.

#### 4.10

If a machine is operating with an earthed neutral, a system earth fault will give rise to zero sequence currents in the machine. This reactance represents the machine's contribution to the total impedance offered to these currents. In practice it is generally low and often outweighed by other impedances present in the circuit.

| Item No.                                                                      | Machine type                                       | Maximum $I_2/I_N$ for continuous operation | Maximum $(I_2/I_N)^2 t$ for operation under fault conditions |
|-------------------------------------------------------------------------------|----------------------------------------------------|--------------------------------------------|--------------------------------------------------------------|
| <b>Salient pole machines</b>                                                  |                                                    |                                            |                                                              |
| 1                                                                             | Indirectly cooled motors                           | 0.1                                        | 20                                                           |
|                                                                               | generators                                         | 0.08                                       | 20                                                           |
|                                                                               | synchronous condensers                             | 0.1                                        | 20                                                           |
| 2                                                                             | directly cooled (inner cooled) stator and/or field |                                            |                                                              |
|                                                                               | motors                                             | 0.08                                       | 15                                                           |
|                                                                               | generators                                         | 0.05                                       | 15                                                           |
|                                                                               | synchronous condensers                             | 0.08                                       | 15                                                           |
| <b>Cylindrical rotor synchronous machines</b>                                 |                                                    |                                            |                                                              |
| 3                                                                             | Indirectly cooled rotor                            |                                            |                                                              |
|                                                                               | air-cooled                                         | 0.1                                        | 15                                                           |
| 4                                                                             | hydrogen-cooled                                    | 0.1                                        | 10                                                           |
|                                                                               | Directly cooled (inner cooled) rotor               |                                            |                                                              |
|                                                                               | ≤ 350 MVA                                          | 0.08                                       | 8                                                            |
|                                                                               | > 350 ≤ 900 MVA                                    | *                                          | **                                                           |
|                                                                               | > 900 ≤ 1250 MVA                                   | *                                          | 5                                                            |
|                                                                               | > 1250 ≤ 1600 MVA                                  | 0.05                                       | 5                                                            |
| * For these machines, the value of $I_2/I_N$ is calculated as follows:        |                                                    |                                            |                                                              |
| $I_2/I_N = 0.08 - \frac{S_N - 350}{3 \times 10^4}$                            |                                                    |                                            |                                                              |
| ** For these machines, the value of $(I_2/I_N)^2 t$ is calculated as follows: |                                                    |                                            |                                                              |
| $(I_2/I_N)^2 t = 8 - 0.00545 (S_N - 350)$                                     |                                                    |                                            |                                                              |
| where $S_N$ is the rated power in MVA.                                        |                                                    |                                            |                                                              |

Table 4.2 Unbalanced operating conditions for synchronous machines (with acknowledgement to IEC34-1)

#### 4.11

#### DIRECT AND QUADRATURE AXIS VALUES

The transient reactance is associated with the field winding and since on salient pole machines this is concentrated on the direct axis, there is no corresponding quadrature axis

value. The value of reactance applicable in the axis is the synchronous reactance, that is,  $X'_q = X_q$ .

The damper winding (or its equivalent) is more widely spread and hence the sub-transient reactance associated with this has a definite quadrature axis value  $X''_q$ .

#### 4.12

### EFFECT OF SATURATION ON MACHINE REACTANCES

In general any electrical machine is designed to avoid severe saturation of its magnetic circuit. However, it is not economically possible to operate at such low densities as to avoid saturation or, more correctly, to reduce it to negligible proportions, and in practice a moderate degree of saturation is accepted, usually about 10%.

Since the armature reaction reactance  $X_{ad}$  is a ratio  $AT_{ar}/AT_c$  it is evident that  $AT_c$  will not vary in a linear manner for different voltages, while  $AT_{ar}$  will remain unchanged. The value of  $X_{ad}$  will vary with the degree of saturation present in the machine, and for extreme accuracy should be determined for the particular conditions involved in any calculation.

All the other reactances, namely  $X_L$ ,  $X'_d$  and  $X''_d$ , are true reactances and actually arise from flux leakage. Much of this leakage occurs in the iron parts of the machines and hence must be affected by saturation. For a given set of conditions, the leakage flux exists as a result of a net m.m.f. which causes it. If the iron circuit is unsaturated its reluctance is low and leakage flux is easily established. If the circuits are highly saturated the reverse is true and the leakage flux is relatively lower, so the reactance under saturated conditions is lower than when unsaturated.

Most calculation methods assume infinite iron permeability and for this reason lead to somewhat idealized unsaturated reactance values. The recognition of a finite and varying permeability makes a solution extremely laborious and in practice a simple factor of approximately 0.9 is taken as representing the reduction in reactance arising from saturation.

It is necessary to distinguish which value of reactance is being measured when on test. The normal direct short-circuit from open-circuit voltage gives a current which is usually several times full load value, so that saturation is present and the reactance measured will be the saturated value. This value is also known as the 'rated voltage' value since it is measured by a short circuit applied with the machine excited to rated voltage.

In some cases, if it is wished to avoid the severe mechanical strain to which a machine is subjected by such a direct short circuit, the test may be made from a suitably reduced voltage so that the initial current is approximately full load value. Saturation is very much reduced and the reactance values measured are virtually unsaturated values. They are best known as 'rated current' values, for obvious reasons.

#### 4.13

### TRANSFORMER

A transformer may be replaced in a power system by an equivalent circuit representing the self impedance of, and the mutual coupling between, the windings. A two-winding transformer can be simply represented as a 'T' network in which the cross member is the short-circuit impedance, and the column the excitation impedance. It is then necessary in fault studies to consider excitation impedance as this is usually many times the magnitude of the short-circuit impedance. With these simplifying assumptions a three-winding transformer becomes a star of three impedances and a four-winding transformer a mesh of six impedances.

The impedances of a transformer in common with other parts can be given in ohms and qualified by a base voltage, or in per unit, percentage terms, and qualified by a base

MVA. Care should be taken with multi-winding transformers to refer all impedances to a common base MVA or to state the base on which each is given. The impedances of static apparatus are independent of the phase sequence of the applied voltage; in consequence, transformer impedances to negative sequence and positive sequence currents are identical. In determining the impedance to zero phase sequence currents, account must be taken of the winding connections, earthing, and, in some cases, the construction type. The existence of a path for zero sequence currents implies a fault to earth and a flow of balancing currents in the windings of the transformer.

#### 4.14

##### 4.14.1

### Two-winding transformers

The two-winding transformer has four terminals, but in most system problems it can be represented by two-terminal or three-terminal equivalent circuits as shown in Figure 4.10. In Figure 4.10(a) terminals  $A'$  and  $B'$  are assumed to be at the same potential. Hence, if the per unit self impedances of the windings are  $Z_{11}$  and  $Z_{22}$  respectively and the mutual impedance between them  $Z_{12}$ , the transformer may be represented by Figure 4.10(b). The circuit in Figure 4.10(b) is similar to that shown in Figure 2.15(a), and can therefore be replaced by an equivalent 'T' as shown in Figure 4.10(c) where:

$$\left. \begin{aligned} Z_1 &= Z_{11} - Z_{12} \\ Z_2 &= Z_{22} - Z_{12} \\ Z_3 &= Z_{12} \end{aligned} \right\} \quad \dots \text{Equation 4.5}$$

$Z_1$  is described as the leakage impedance of winding  $AA'$  and  $Z_2$  the leakage impedance of winding  $BB'$ .

Impedance  $Z_3$  is the mutual impedance between the windings, usually represented by  $X_M$ , the magnetizing reactance paralleled with the hysteresis and eddy current loops as shown in Figure 4.10(d).

If the secondary of the transformers is short-circuited and  $Z_3$  is assumed to be large with respect to  $Z_1$  and  $Z_2$ , then the short-circuit impedance viewed from the terminals  $AA'$  is  $Z_T = Z_1 + Z_2$  and the transformer can be replaced by a two-terminal equivalent circuit as shown in Figure 4.10(e).

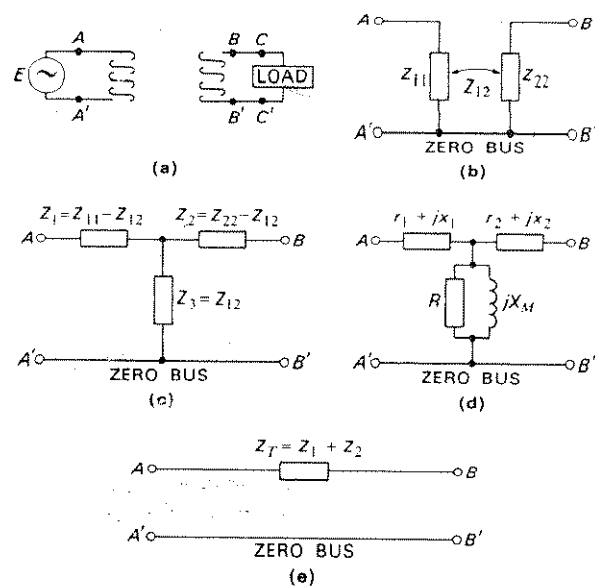


Figure 4.10 Equivalent circuits for a two-winding transformer.

The relative magnitudes of  $Z_T$  and  $X_M$  are of the order of 10% and 2000% respectively.  $Z_T$  and  $X_M$  rarely have to be considered together, so that the transformer may be represented either as a series impedance or as an excitation impedance, according to the problem being studied.

Typical values of percentage reactance for two-winding transformers are given in Table 4.3. However, since the impedance is a design feature of a transformer, the actual values for practical equipment should be obtained from the manufacturers. Transformers designed to work at 60 Hz will have substantially the same impedance as their 50 Hz counterparts.

| MVA rating | Voltage of higher voltage winding |       |       |        |        |
|------------|-----------------------------------|-------|-------|--------|--------|
|            | 11 kV                             | 33 kV | 66 kV | 132 kV | 275 kV |
| 0.1        | 3                                 | —     | —     | —      | —      |
| 0.5        | 4.0                               | 4.5   | —     | —      | —      |
| 1.0        | 4.5                               | 5.0   | 6.0   | —      | —      |
| 5.0        | 5.5                               | 6.0   | 7.0   | —      | —      |
| 10.0       | 7.0                               | 8.0   | 9.0   | —      | —      |
| 20.0       | 9.0                               | 10.0  | 11.0  | —      | —      |
| 40.0       | —                                 | 12.0  | 14.0  | 16     | —      |
| 80.0       | —                                 | —     | 16.0  | 18     | 20     |
| 160.0      | —                                 | —     | —     | 20     | 22     |
| 320.0      | —                                 | —     | —     | —      | 24     |

Note: Impedance values may vary widely from the above over a range of 0.8 to 2 times the above figures

Table 4.3 Typical % impedances of two winding transformers of various ratings and voltages at 50 Hz

#### 4.14.2

##### Three-winding transformers

If excitation impedance is neglected the equivalent circuit of a three-winding transformer may be represented by a star of impedances, as shown in Figure 4.11, where  $P$ ,  $T$  and  $S$  are the primary, tertiary and secondary windings respectively. The impedance of any of these branches can be determined by considering the short-circuit impedance between pairs of windings with the third open.

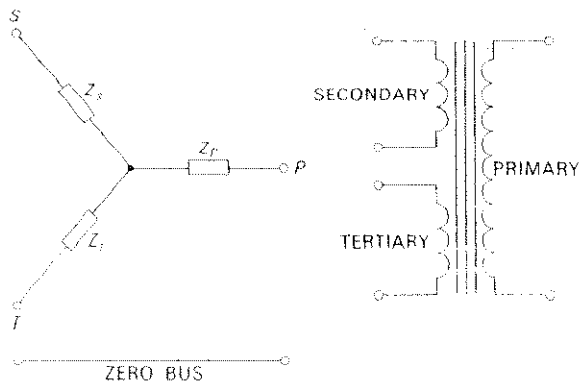


Figure 4.11 Equivalent circuit for a three-winding transformer.

Thus:

$$\left. \begin{aligned} Z_P + Z_S &= Z_{PS} \\ Z_T + Z_S &= Z_{TS} \\ Z_P + Z_T &= Z_{PT} \end{aligned} \right\} \quad \dots \text{Equation 4.6}$$

from which

$$\left. \begin{aligned} Z_P &= \frac{1}{2}(Z_{PS} + Z_{PT} - Z_{TS}) \\ Z_S &= \frac{1}{2}(Z_{PS} + Z_{TS} - Z_{PT}) \\ Z_T &= \frac{1}{2}(Z_{PT} + Z_{TS} - Z_{PS}) \end{aligned} \right\} \quad \dots \text{Equation 4.7}$$

One of the branches, usually the least important, may exhibit negative impedance.

#### 4.15

The flow of zero sequence currents in a transformer is only possible when the transformer forms part of a closed loop for uni-directional currents and ampere-turn balance is maintained between windings.

The positive sequence equivalent circuit is still maintained to represent the transformer, but now there are certain conditions attached to its connection into the external circuit. The order of excitation impedance is very much lower than for the positive sequence circuit; it will be roughly between 1 and 4 per unit, but still high enough to be neglected in most fault studies.

The mode of connection of a transformer to the external circuit is determined by taking account of each winding arrangement and its connection or otherwise to ground. If zero sequence currents can flow into and out of a winding, the winding terminal is connected to the external circuit (that is, link  $a$  is closed in Figure 4.12). If zero sequence currents can circulate in the winding without flowing in the external circuit, the winding terminal is connected directly to the zero bus (that is, link  $b$  is closed in Figure 4.12).

Table 4.4 gives the zero sequence connections of some common two- and three-winding transformer arrangements applying the above rules.

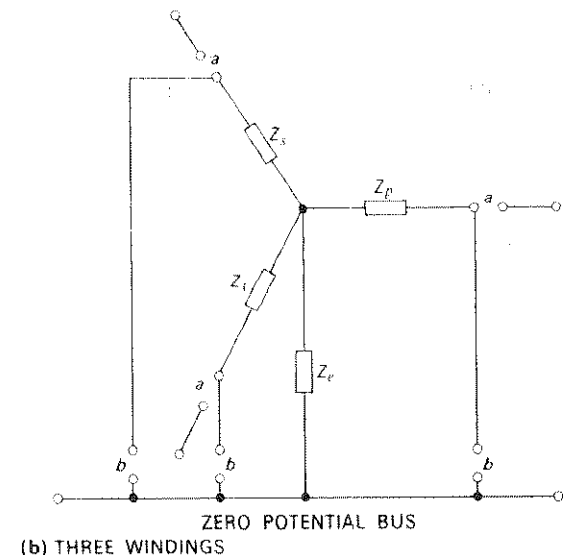
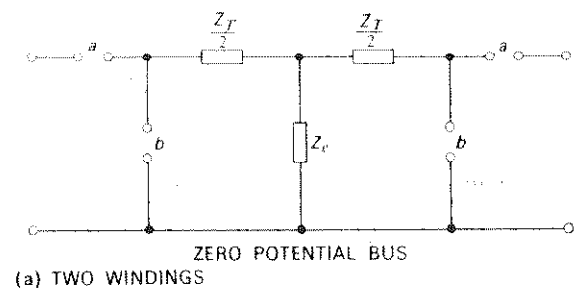


Figure 4.12 Zero sequence equivalent circuits.

The exceptions to the general rule of neglecting magnetizing impedance occur when the transformer is star/star and either or both neutrals are earthed. In these circumstances the transformer is connected to the zero bus through the magnetizing impedance. Where a three-phase transformer bank is arranged without interlinking magnetic flux (that is, a three-phase shell type, or three single-phase units) and provided there is a path for zero sequence currents, the zero sequence impedance is equal to the positive sequence



# Connections and zero phase sequence current paths

## Zero phase sequence network

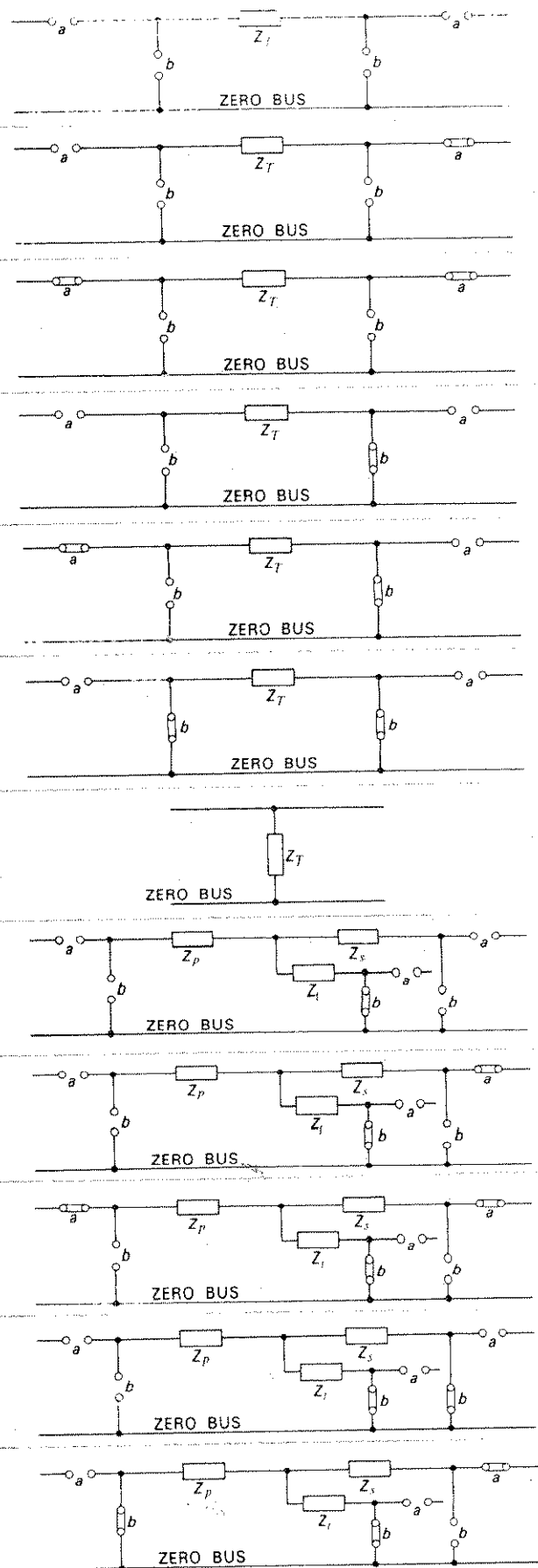
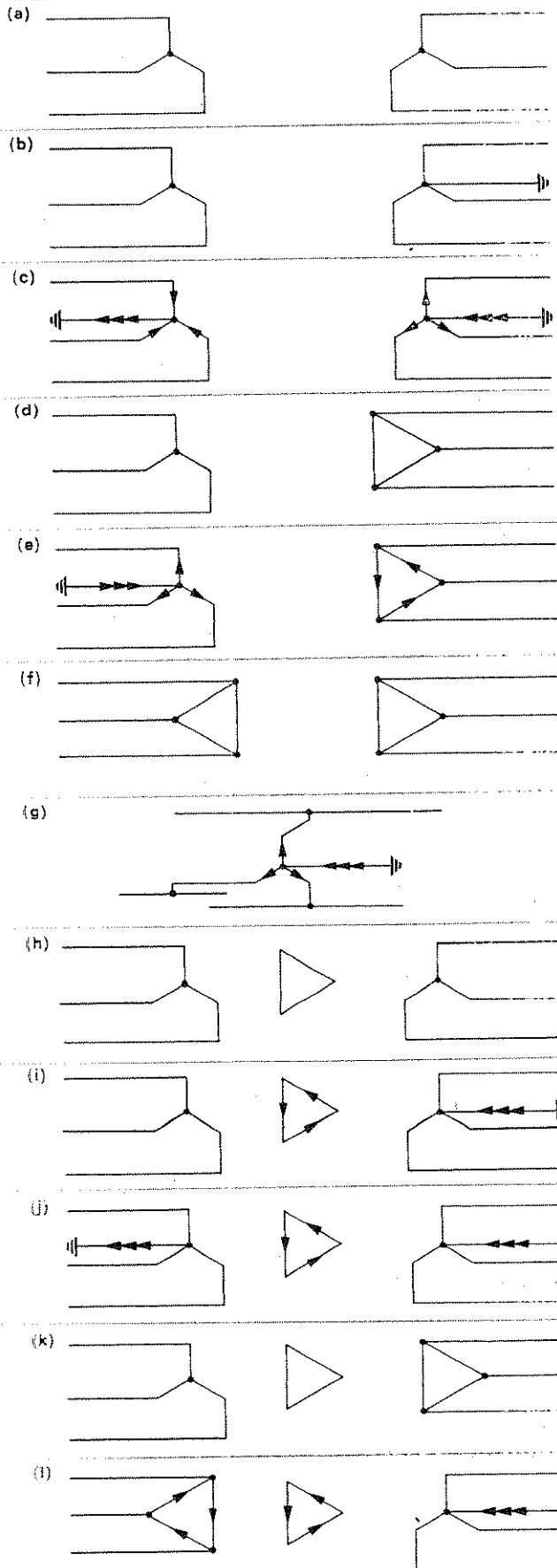


Fig. 4.4 Zero sequence equivalent circuit connections.

impedance. In the case of three-phase core type units, the zero sequence fluxes produced by zero sequence currents can find a high reluctance path, the effect being to reduce the zero sequence impedance by about one-tenth.

However, in calculations, it is usual to ignore this variation and consider the positive and zero sequence impedances to be equal.

#### 4.16

The auto-transformer is characterized by a single continuous winding, part of which is shared by both the high and low voltage circuits, as shown in Figure 4.13(a). The 'common' winding is the winding between the low voltage terminals, whereas the remainder of the winding, belonging exclusively to the high voltage circuit, is designated the 'series' winding, and, combined with the 'common' winding, forms the 'series-common' winding between the high voltage terminals.

Three-phase auto-transformer banks generally have star connected main windings, the neutral of which is normally connected solidly to earth. In addition, it is common practice to include a third winding connected in delta called the tertiary winding, as shown in Figure 4.13(b).

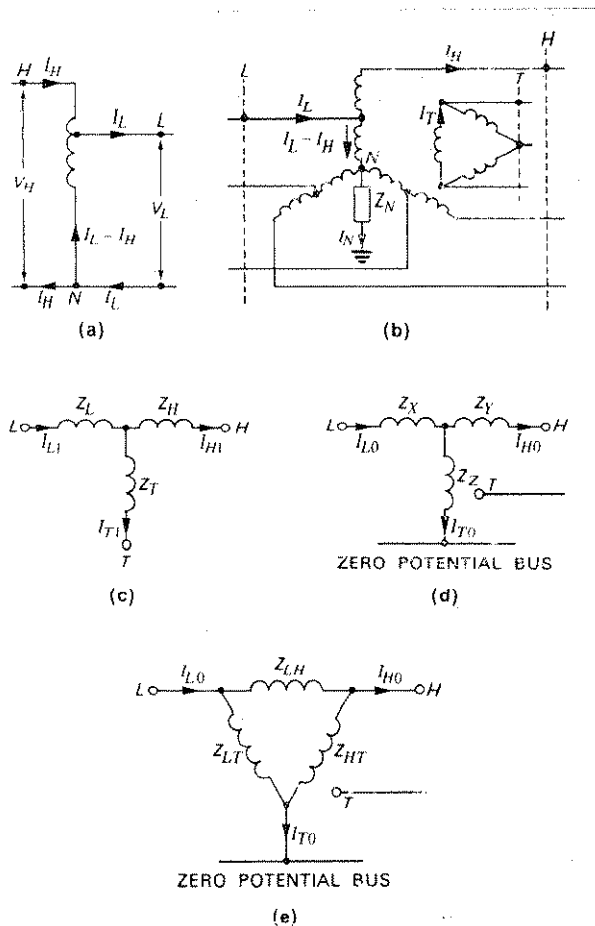


Figure 4.13 Equivalent circuit of auto-transformer.

#### 4.16.1

##### Positive sequence equivalent circuit

The positive sequence equivalent circuit of a three-phase auto-transformer bank is the same as that of a two- or three-winding transformer. The star equivalent for a three-winding transformer, for example, is obtained in the same manner, with the difference that the impedances between windings are designated as follows:

$$\left. \begin{aligned} Z_L &= \frac{1}{2}(Z_{sc-c} + Z_{c-t} - Z_{sc-t}) \\ Z_H &= \frac{1}{2}(Z_{sc-c} + Z_{sc-t} - Z_{c-t}) \\ Z_T &= \frac{1}{2}(Z_{sc-t} + Z_{c-t} - Z_{sc-c}) \end{aligned} \right\} \dots \text{Equation 4.8}$$

where  $Z_{sc-t}$  = impedance between 'series-common' and tertiary windings.

$Z_{sc-c}$  = impedance between 'series-common' and 'common' windings.

$Z_{c-t}$  = impedance between 'common' and tertiary windings.

When no load is connected to the delta tertiary, the point T will be open-circuited and the short-circuit impedance of the transformer becomes  $Z_L + Z_H = Z_{sc-c}$ , that is, similar to the equivalent circuit of a two-winding transformer, with magnetizing impedance neglected; see Figure 4.13(c).

#### 4.16.2

##### Zero sequence equivalent circuit

The zero sequence equivalent circuit is derived in a similar manner to the positive sequence circuit, except that, as there is no identity for the neutral point, the current in the neutral and the neutral voltage cannot be given directly. Furthermore, in deriving the branch impedances, account must be taken of any impedance in the neutral  $Z_n$ , as shown in the following equations, where  $Z_x$ ,  $Z_y$  and  $Z_z$  are the impedances of the low, high and tertiary windings respectively and  $N$  is the ratio between the series and common windings.

$$\left. \begin{aligned} Z_x &= Z_L + 3Z_n \frac{N}{(N+1)} \\ Z_y &= Z_H - 3Z_n \frac{N}{(N+1)^2} \\ Z_z &= Z_T + 3Z_n \frac{1}{(N+1)} \end{aligned} \right\} \dots \text{Equation 4.9}$$

Figure 4.13(d) shows the equivalent circuit of the transformer bank. Currents  $I_{L0}$  and  $I_{H0}$  are those circulating in the low and high voltage circuits respectively. The difference between these currents, expressed in amperes, is the current in the common winding.

The current in the neutral impedance is three times the current in the common winding.

#### 4.16.3

##### Special conditions of neutral earthing

With a solidly grounded neutral,  $Z_n = 0$ , the branch impedances  $Z_x$ ,  $Z_y$ ,  $Z_z$ , become  $Z_L$ ,  $Z_H$ ,  $Z_T$ , that is, identical to the corresponding positive sequence equivalent circuit, except that the equivalent impedance  $Z_T$  of the delta tertiary is connected to the zero potential bus in the zero sequence network.

When the neutral is ungrounded  $Z_n = \infty$  and the impedances of the equivalent star also become infinite because there are apparently no paths for zero sequence currents between the windings, although a physical circuit exists and ampere-turn balance can be obtained. A solution is to use an equivalent delta circuit (see Figure 4.13(e)), and evaluate the elements of the delta directly from the actual circuit. The method requires three equations corresponding to three assumed operating conditions. Solving these equations will relate the delta impedances to the impedance between the series and tertiary windings, as follows:

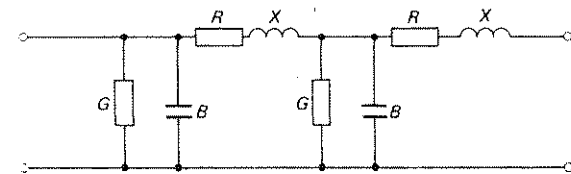
$$\left. \begin{aligned} Z_{LH} &= Z_{s-t} \frac{N^2}{(1+N)} \\ Z_{LT} &= -Z_{s-t} N \\ Z_{HT} &= Z_{s-t} \frac{N}{(1+N)} \end{aligned} \right\} \dots \text{Equation 4.10}$$

With the equivalent delta replacing the star impedances in the auto-transformer zero sequence equivalent circuit the transformer can be combined with the system impedances in the usual manner to obtain the system zero sequence diagram.

#### 4.17

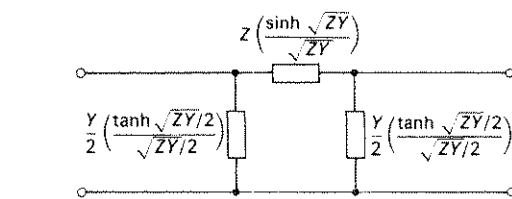
In this section a description of common overhead lines and cable systems is given, together with tables of their important characteristics. The formulae for calculating the characteristics are developed to give a basic idea of the factors involved, and to enable calculations to be made for systems other than those tabulated.

A transmission circuit may be represented by an equivalent  $\pi$  or  $T$  network using lumped constants as shown in Figure 4.14.  $Z$  is the total series impedance  $(R + jX)L$  and  $Y$  is the total shunt admittance  $(G + jB)L$  where  $L$  is the circuit length. The terms inside the brackets in Figure 4.14 are correction factors which allow for the fact that in the actual circuit the parameters are distributed over the whole length of the circuit and not lumped, as in the equivalent circuits.

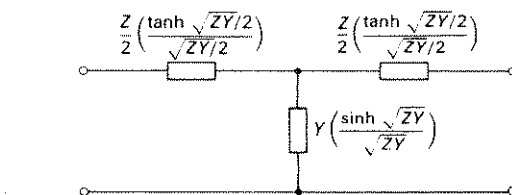


SERIES IMPEDANCE  $Z = R + jX$  per unit length  
SHUNT ADMITTANCE  $Y = G + jB$  per unit length

(a) ACTUAL TRANSMISSION CIRCUIT



(b)  $\pi$  EQUIVALENT



(c)  $T$  EQUIVALENT

NOTE:  $Z$  and  $Y$  in (b) and (c) are the total series impedance and shunt admittance respectively.  $Z = (R + jX)L$  and  $Y = (G + jB)L$  where  $L$  is the circuit length.

$$\frac{\sinh \sqrt{ZY}}{\sqrt{ZY}} = 1 + \frac{ZY}{6} + \frac{Z^2 Y^2}{120} + \frac{Z^3 Y^3}{5040} + \dots$$

$$\frac{\tanh \sqrt{ZY}/2}{\sqrt{ZY}/2} = 1 - \frac{ZY}{12} + \frac{Z^2 Y^2}{120} - \frac{17Z^3 Y^3}{20,160} + \dots$$

#### 4.14 Transmission circuit equivalents.

For short lines it is usually possible to ignore the shunt admittance, which greatly simplifies calculations, but on longer lines it must be included. Another simplification can be made is that of assuming the conductor configuration to be symmetrical. The self impedance of each conductor becomes  $Z_p$ , and the mutual impedance between conductors becomes  $Z_m$ . However, for rigorous calculations a detailed treatment is necessary, with account being taken of the spacing of a conductor in relation to its neighbour and earth.

#### 4.18

The self impedance of a conductor with an earth return and the mutual impedance between two parallel conductors with a common earth return are given by the Carson equations:

$$Z_p = R + 0.000988f + j0.0029f \log_{10} \frac{2}{dc} \quad \dots \text{Equation 4.11}$$

$$Z_m = 0.000988f + j0.0029f \log_{10} \frac{D}{D_c}$$

where  $R$  = conductor a.c. resistance (ohms/km)

$dc$  = geometric mean radius of a single conductor

$D$  = spacing between the parallel conductors

$f$  = system frequency

$D_c$  = equivalent spacing of the earth return path

$= 216 \sqrt{\rho/f}$  where  $\rho$  is earth resistivity (ohms/cm<sup>2</sup>).

The above formulae give the impedances in ohms/km. It should be noted that the last terms in Equation 4.11 are very similar to the classical inductance formulae for long straight conductors.

The geometric mean radius (GMR) of a conductor is an equivalent radius which allows the inductance formula to be reduced to a single term. It should be remembered that the inductance of a solid conductor is a function of the internal flux linkages in addition to those external to it. If the original conductor can be replaced by an equivalent which is a hollow cylinder with infinitesimally thin walls the current is confined to the surface of the conductor, and there can be no internal flux. The radius of the equivalent conductor is the geometric mean radius. If the original conductor is a solid cylinder having a radius  $r$  its equivalent has a radius of  $0.779r$ .

It can be shown that the sequence impedances for a symmetrical three-phase circuit are:

$$\left. \begin{aligned} Z_1 = Z_2 = Z_p - Z_m \\ Z_0 = Z_p + 2Z_m \end{aligned} \right\} \dots \text{Equation 4.12}$$

where  $Z_p$  and  $Z_m$  are given by Equation 4.11. Substituting Equation 4.11 in Equation 4.12 gives:

$$\left. \begin{aligned} Z_1 = Z_2 = R + j0.0029f \log_{10} \frac{D}{dc} \\ Z_0 = R + 0.00296f + j0.00869f \log_{10} \frac{D_c}{\sqrt[3]{dcD^2}} \end{aligned} \right\} \dots \text{Equation 4.13}$$

In the formula for  $Z_0$  the expression  $\sqrt[3]{dcD^2}$  is the geometric mean radius of the conductor group.

Where the circuit is not symmetrical, the usual case, symmetry can be maintained by transposing the conductors so that each conductor is in each phase position for one third of the circuit length. If  $A$ ,  $B$  and  $C$  are the spacings between conductors  $bc$ ,  $ca$  and  $ab$  then  $D$  in the above equations becomes the geometric mean distance between conductors, equal to  $\sqrt[3]{ABC}$ .

Writing  $D_c = \sqrt[3]{dcD^2}$ , the sequence impedances in ohms/km at 50 Hz become:

$$\left. \begin{aligned} Z_1 = Z_2 = R + j0.145 \log_{10} \frac{\sqrt[3]{ABC}}{dc} \\ Z_0 = (R + 0.148) + j0.434 \log_{10} \frac{D_c}{D_c} \end{aligned} \right\} \dots \text{Equation 4.14}$$

It can be shown that the potential of a conductor  $a$  above ground due to its own charge  $qa$  and a charge  $-qa$  on its image is:

$$V_a = 2qa \log_e \frac{2h}{r} \quad \dots \text{Equation 4.15}$$

where  $h$  is the height above ground of the conductor and  $r$  is the radius of the conductor, as shown in Figure 4.15.

Similarly it can be shown that the potential of a conductor  $a$  due to a charge  $qb$  on a neighbouring conductor  $b$  and the charge  $-qb$  on its image is:

$$V'_a = 2qb \log_e \frac{D'}{D} \quad \dots \text{Equation 4.16}$$

where  $D$  is the spacing between conductors  $a$  and  $b$  and  $D'$  is the spacing between conductor  $b$  and the image of conductor  $a$  as shown in Figure 4.15.

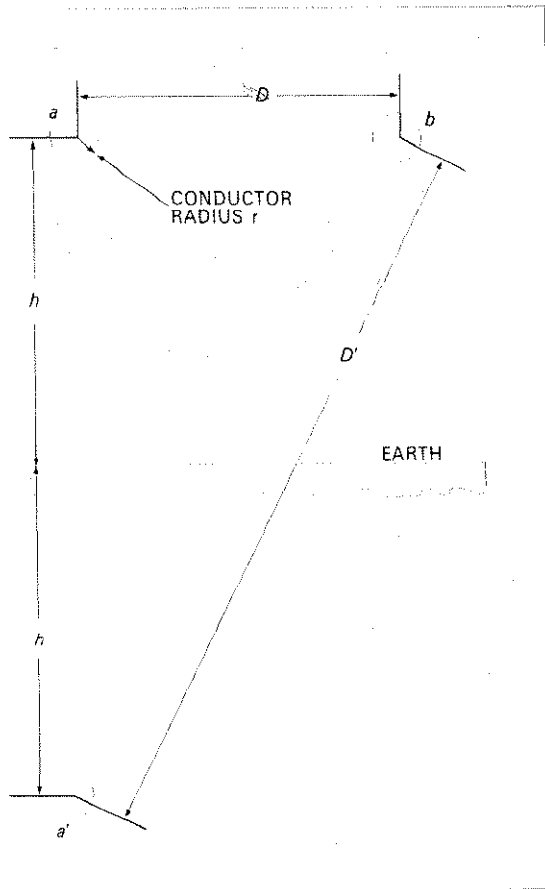


Figure 4.15 Geometry of two parallel conductors  $a$  and  $b$  and the image of  $a$  ( $a'$ ).

Since the capacitance  $C = q/V$  and the capacitive reactance  $X_c = 1/\omega C$  it follows that the self and mutual capacitive reactance of the conductor system in Figure 4.15 can be obtained directly from Equations 4.15 and 4.16. Further, as leakage can usually be neglected, the self and mutual shunt impedances  $Z'_p$  and  $Z'_m$  in megohm-km at a system frequency of 50 Hz are:

$$\left. \begin{aligned} Z'_p &= -j0.132 \log_{10} \frac{2h}{r} \\ Z'_m &= -j0.132 \log_{10} \frac{D'}{D} \end{aligned} \right\} \quad \dots \text{Equation 4.17}$$

where the distances above ground are great in relation to the conductor spacing, which is the case with overhead lines  $2h \approx D'$ . From Equation 4.12, the sequence impedances of a symmetrical three-phase circuit are:

$$\left. \begin{aligned} Z_1 &= Z_2 = -j0.132 \log_{10} \frac{D}{r} \\ Z_0 &= -j0.396 \log_{10} \frac{D'}{\sqrt[3]{rD^2}} \end{aligned} \right\} \quad \dots \text{Equation 4.18}$$

It should be noted that the logarithmic terms above are similar to those in Equation 4.13 except that  $r$  is the actual radius of the conductors and  $D'$  is the spacing between the conductors and their images.

Again, where the conductors are not symmetrically spaced but transposed, Equation 4.18 can be re-written making use of the geometric mean distance between conductors,  $\sqrt[3]{ABC}$ , and giving the distance of each conductor above ground, that is,  $h_a, h_b, h_c$ , as follows:

$$\left. \begin{aligned} Z_1 &= Z_2 = -j0.132 \log_{10} \frac{\sqrt[3]{ABC}}{r} \\ Z_0 &= -j0.132 \log_{10} \frac{8h_a h_b h_c}{r \sqrt[3]{A^2 B^2 C^2}} \end{aligned} \right\} \quad \dots \text{Equation 4.19}$$

#### 4.20

##### OVERHEAD LINE CIRCUITS WITH OR WITHOUT EARTH WIRES

Typical configurations of overhead line circuits operating at U.K. transmission voltages are given in Figure 4.16. It may be seen that the phase conductors are not symmetrically disposed to each other and therefore, as previously indicated, electrostatic and electromagnetic unbalances will result, which can be largely eliminated by transposition. Modern practice is to build overhead lines without transposition towers to reduce costs; this must be taken into account in rigorous calculations of the unbalances.

It should be noted that the line configuration and conductor spacings are influenced, not only by voltage, but also by many other factors including type of insulators, type of support, span length, conductor sag and the nature of terrain and external climatic loadings. Therefore there can be large variations in spacings between different line designs for the same voltage level, so those depicted in Figure 4.16 are only typical examples.

When calculating the phase self and mutual impedances, Equations 4.11 and 4.17 may be used, but it should be remembered that in this case  $Z_p$  is calculated for each conductor and  $Z_m$  for each pair of conductors. Detailed methods of analysis are given in several well known works on this subject, a very useful reference being E.R.A. Technical Report O/T4A—'Electrical Characteristics of Overhead Lines'. This section is not, therefore, intended to give a detailed analysis, but rather to show the general method of formulating the equations, taking the calculation of series impedance as an example and assuming a single circuit line with a single earth wire.

The phase voltage drops  $V_a, V_b, V_c$  of a single circuit line with a single earth wire due to currents  $I_a, I_b, I_c$  flowing in the phases and  $I_e$  in the earth wire are:

$$\left. \begin{aligned} V_a &= Z_{aa} I_a + Z_{ab} I_b + Z_{ac} I_c + Z_{ae} I_e \\ V_b &= Z_{ba} I_a + Z_{bb} I_b + Z_{bc} I_c + Z_{be} I_e \\ V_c &= Z_{ca} I_a + Z_{cb} I_b + Z_{cc} I_c + Z_{ce} I_e \\ 0 &= Z_{ea} I_a + Z_{eb} I_b + Z_{ec} I_c + Z_{ee} I_e \end{aligned} \right\} \quad \dots \text{Equation 4.20}$$

where

$$Z_{aa} = R + 0.000988f + j0.0029f \log_{10} \frac{D_e}{dc}$$

$$Z_{ab} = 0.000988f + j0.0029f \log_{10} \frac{D_e}{D} \text{ and so on.}$$

The equation required for the calculation of shunt voltage drops is identical to Equation 4.20 in form, except that primes must be included, the impedances being derived from Equation 4.17.

From Equation 4.20 it can be seen that:

$$-I_e = \frac{Z_{ea}}{Z_{ee}} I_a + \frac{Z_{eb}}{Z_{ee}} I_b + \frac{Z_{ec}}{Z_{ee}} I_c$$

Making use of this relation the self and mutual impedances of the phase conductors can be modified using the following formula:

$$J_{nm} = Z_{nm} - \frac{Z_{ne} Z_{me}}{Z_{ee}} \quad \dots \text{Equation 4.21}$$

For example:

$$J_{aa} = Z_{aa} - \frac{Z_{ae}^2}{Z_{ee}}$$

$$J_{ab} = Z_{ab} - \frac{Z_{ae} Z_{be}}{Z_{ee}} \text{ and so on.}$$

So Equation 4.20 can be simplified while still taking account of the effect of the earth wire by deleting the fourth row and fourth column and substituting  $J_{aa}$  for  $Z_{aa}$ ,  $J_{ab}$  for  $Z_{ab}$ , and so on, calculated using Equation 4.21. The single circuit line with a single earth wire can therefore be replaced by an equivalent single circuit line having phase self and mutual impedances  $J_{aa}$ ,  $J_{ab}$ , and so on.

It can be shown from the symmetrical component theory given in Chapter 3 that the sequence voltage drops of a general three-phase circuit are:

$$\left. \begin{aligned} V_0 &= Z_{00} I_0 + Z_{01} I_1 + Z_{02} I_2 \\ V_1 &= Z_{10} I_0 + Z_{11} I_1 + Z_{12} I_2 \\ V_2 &= Z_{20} I_0 + Z_{21} I_1 + Z_{22} I_2 \end{aligned} \right\} \quad \dots \text{Equation 4.22}$$

And, from Equation 4.20 modified as indicated above and Equation 4.22, the sequence impedances are:

$$\left. \begin{aligned} Z_{00} &= \frac{1}{3}(J_{aa} + J_{bb} + J_{cc}) - \frac{2}{3}(J_{ab} + J_{bc} + J_{ac}) \\ Z_{11} = Z_{22} &= \frac{1}{3}(J_{aa} + J_{bb} + J_{cc}) - \frac{1}{3}(J_{ab} + J_{bc} + J_{ac}) \\ Z_{12} &= \frac{1}{3}(J_{aa} + a^2 J_{bb} + a J_{cc}) + \frac{2}{3}(a J_{ab} + a^2 J_{ac} + J_{bc}) \\ Z_{21} &= \frac{1}{3}(J_{aa} + a J_{bb} + a^2 J_{cc}) + \frac{2}{3}(a^2 J_{ab} + a J_{ac} + J_{bc}) \\ Z_{20} = Z_{01} &= \frac{1}{3}(J_{aa} + a^2 J_{bb} + a J_{cc}) - \frac{1}{3}(a J_{ab} + a^2 J_{ac} + J_{bc}) \\ Z_{10} = Z_{02} &= \frac{1}{3}(J_{aa} + a J_{bb} + a^2 J_{cc}) - \frac{1}{3}(a^2 J_{ab} + a J_{ac} + J_{bc}) \end{aligned} \right\} \quad \dots \text{Equation 4.23}$$

The development of these equations for double circuit lines with two earth wires is similar except that more terms are involved.

The sequence mutual impedances are very small and can usually be neglected; this also applies for double circuit lines except for the mutual impedance between the zero sequence circuits, namely ( $Z_{00'} = Z_{0'0}$ ). Table 4.5 gives typical values of all sequence self and mutual impedances for single and double circuit lines with earth wires, illustrated in Figure 4.16.

All conductors are 400 sq.mm. ACSR, except for the 132 kV double circuit example where they are 200 sq.mm.

#### 4.2i

##### Example 4.2i: Fault current

Consider an earthed, infinite busbar source behind a length of transmission line as shown in Figure 4.17(a). An earth fault involving phase A is assumed to occur at F. If the driving voltage is  $E$  and the fault current is  $I_a$  then the earth fault impedance is  $Z_e$ . From symmetrical component theory (see Chapter 3):

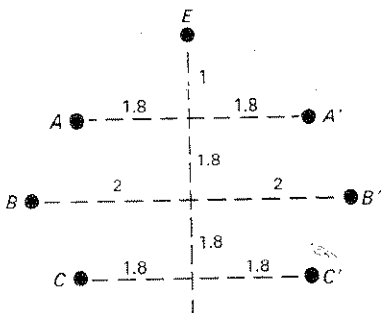
$$I_a = \frac{3E}{Z_1 + Z_2 + Z_0}$$

| Sequence impedance                          | 132 kV<br>Single circuit<br>line<br>(400 sq mm) | 380 kV<br>Single circuit<br>line<br>(400 sq mm) | 132 kV<br>Double circuit<br>line<br>(200 sq mm) | 275 kV<br>Double circuit<br>line<br>(400 sq mm) |
|---------------------------------------------|-------------------------------------------------|-------------------------------------------------|-------------------------------------------------|-------------------------------------------------|
| $Z_{00} = (Z_{0'0'})$                       | 1.0782<br>/73° 54'                              | 0.8227<br>/70° 36'                              | 1.1838<br>/71° 6'                               | 0.9520<br>/76° 46'                              |
| $Z_{11} = Z_{22} = (Z_{1'1'})$              | 0.3947<br>/78° 54'                              | 0.3712<br>/75° 57'                              | 0.4433<br>/66° 19'                              | 0.3354<br>/74° 35'                              |
| $(Z_{0'0} = Z_{00'})$                       | —                                               | —                                               | 0.6334<br>/71° 2'                               | 0.5219<br>/75° 43'                              |
| $Z_{01} = Z_{20} = (Z_{0'1'} = Z_{2'0'})$   | 0.0116<br>/— 166° 52'                           | 0.0094<br>/— 39° 28'                            | 0.0257<br>/— 63° 25'                            | 0.0241<br>/— 72° 14'                            |
| $Z_{02} = Z_{10} = (Z_{0'2'} = Z_{1'0'})$   | 0.0185<br>/5° 8'                                | 0.0153<br>/28° 53'                              | 0.0197<br>/— 94° 58'                            | 0.0217<br>/— 100° 20'                           |
| $Z_{12} = (Z_{1'2'})$                       | 0.0255<br>/— 40° 9'                             | 0.0275<br>/147° 26'                             | 0.0276<br>/161° 17'                             | 0.0281<br>/149° 46'                             |
| $Z_{21} = (Z_{2'1'})$                       | 0.0256<br>/— 139° 1'                            | 0.0275<br>/27° 29'                              | 0.0277<br>/37° 13'                              | 0.0282<br>/29° 6'                               |
| $(Z_{1'1'} = Z_{1'1} = Z_{2'2'} = Z_{2'2})$ | —                                               | —                                               | 0.0114<br>/88° 6'                               | 0.0129<br>/88° 44'                              |
| $(Z_{0'1'} = Z_{0'1} = Z_{2'0'} = Z_{2'0})$ | —                                               | —                                               | 0.0140<br>/— 93° 44'                            | 0.0185<br>/— 91° 16'                            |
| $(Z_{0'2'} = Z_{0'2} = Z_{1'0'} = Z_{1'0})$ | —                                               | —                                               | 0.0150<br>/— 44° 11'                            | 0.0173<br>/— 77° 2'                             |
| $(Z_{1'2} = Z_{12'})$                       | —                                               | —                                               | 0.0103<br>/145° 10'                             | 0.0101<br>/149° 20'                             |
| $(Z_{2'1} = Z_{21'})$                       | —                                               | —                                               | 0.0106<br>/30° 56''                             | 0.0102<br>/27° 31''                             |

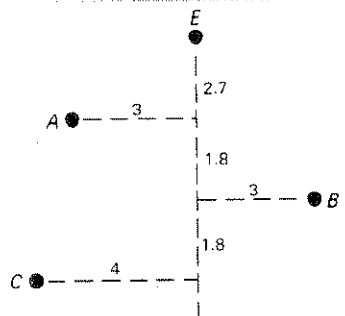
Table 4.5 Sequence self and mutual impedances for various lines (impedances in brackets refer to double circuit lines only) (all impedances are in ohms/km)



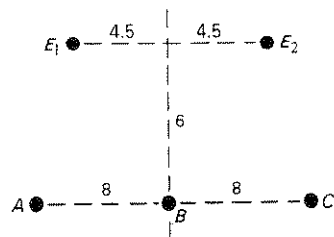
11 kV SINGLE CIRCUIT



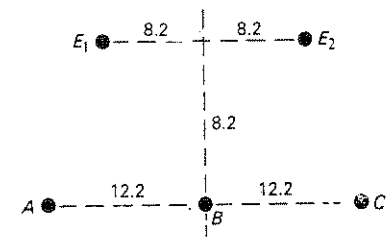
33 kV DOUBLE CIRCUIT



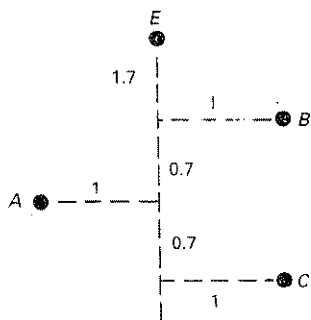
132 kV SINGLE CIRCUIT



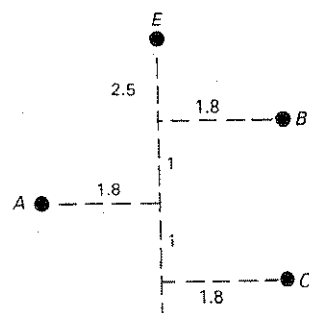
220 kV SINGLE CIRCUIT



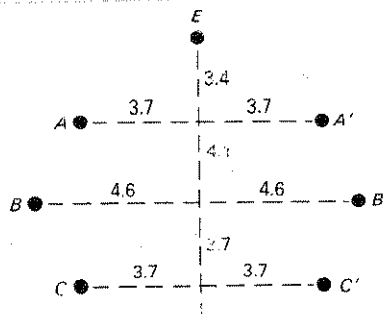
380 kV SINGLE CIRCUIT



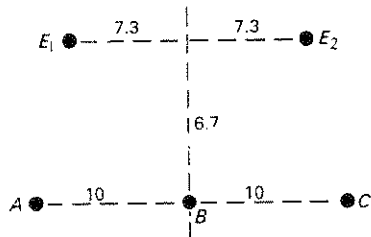
11 kV SINGLE CIRCUIT



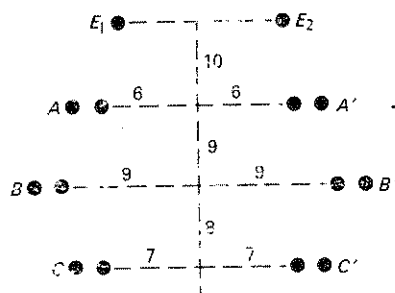
66 kV WOOD POLES



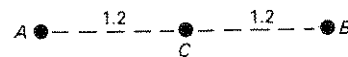
132 kV DOUBLE CIRCUIT



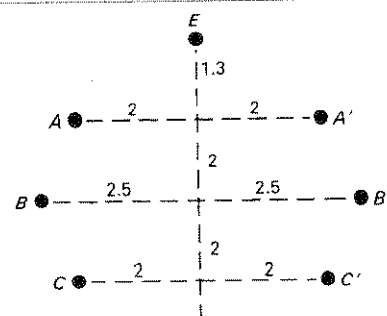
275 kV SINGLE CIRCUIT



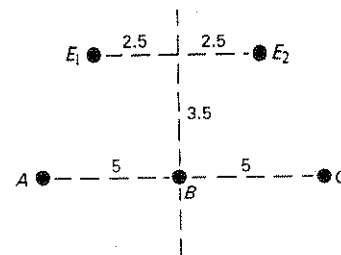
400 kV DOUBLE CIRCUIT



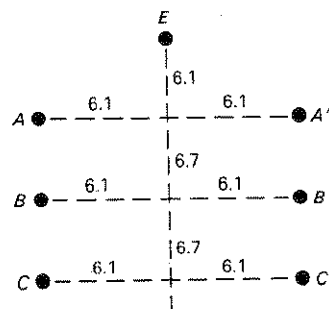
33 kV SINGLE CIRCUIT



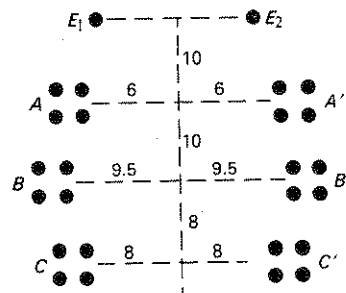
66 kV DOUBLE CIRCUIT



110 kV WOOD POLES



275 kV DOUBLE CIRCUIT



400 kV DOUBLE CIRCUIT

Figure 4.16 Typical overhead line spacings (metres).

thus

$$Z = \frac{2Z_1 + Z_0}{3}$$

since, as shown,  $Z_1 = Z_2$  for a transmission circuit. From Equations 4.12,  $Z_1 = Z_p - Z_m$  and  $Z_0 = Z_p + 2Z_m$ . Thus, substituting these values in the above equation gives  $Z = Z_p$ . This relation is physically valid because  $Z_p$  is the self impedance of a single conductor with an earth return. Similarly, for a phase fault between phases B and C at F:

$$I = -I_c = \frac{\sqrt{3}E}{2Z_1}$$

where  $\sqrt{3}E$  is the voltage between phases and  $2Z_1$  is the impedance of the fault loop.

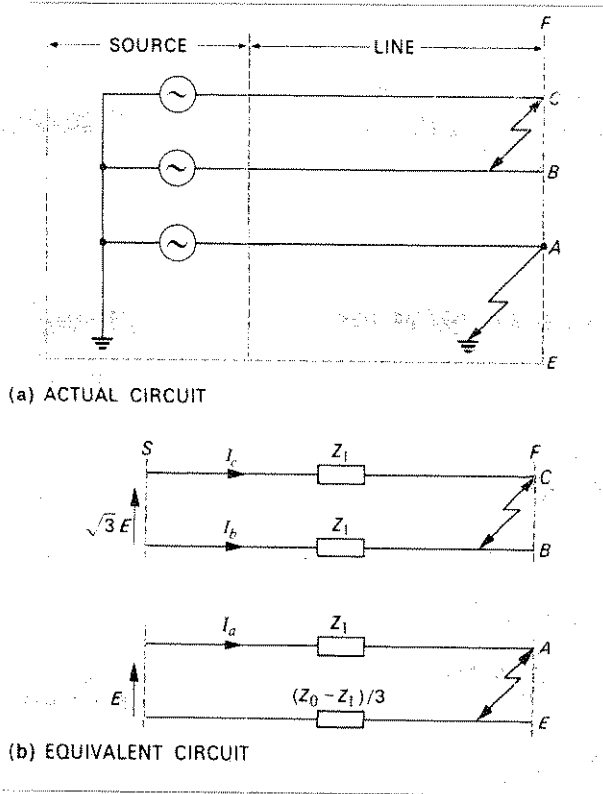


Figure 4.17 Three-phase equivalent of a transmission circuit.

Making use of the above relations a transmission circuit may be represented, without any loss in generality, by the equivalent of Figure 4.17(b), where  $Z_1$  is the phase impedance to the fault and  $(Z_0 - Z_1)/3$  is the impedance of the earth path, there being no mutual impedance between the phases or between phase and earth. The equivalent is valid for single and double circuit lines except that for double circuit lines there is zero sequence mutual impedance, hence  $Z_0 = (Z_{00} - Z_{00})$ .

The equivalent of Figure 4.17(b) is valuable in distance relay applications because the phase and earth fault relays are set to measure  $Z_1$  and are compensated for the earth return impedance  $(Z_0 - Z_1)/3$ .

It is customary to quote the impedances of a transmission circuit in terms of  $Z_1$  and the ratio  $Z_0/Z_1$ , since in this form they are most directly useful. By definition, the positive sequence impedance  $Z_1$  is a function of the conductor spacing and radius, whereas the  $Z_0/Z_1$  ratio is dependent primarily on the level of earth resistivity  $\rho$ . Tables 4.6, 4.7 and 4.8 give the variations of zero sequence impedance,  $Z_0$ , with earth resistivity  $\rho$  for 11 kV, 33 kV, 66 kV, 132 kV, 275 kV and 400 kV lines in use in the UK. In addition the variation in compensation given to distance relays,  $\frac{1}{3}(Z_0/Z_1 - 1)$ , is shown. Further details may be found in Chapter 11.

## 4.22

The basic formulae for calculating the series and shunt impedances of a transmission circuit, Equations 4.11 and 4.17, may be applied for evaluating cable parameters; since the conductor configuration is normally symmetrical GMD and GMR values can be used without risk of appreciable errors. However, the formulae must be modified by the inclusion of empirical factors to take account of sheath and screen effects. A useful general reference on cable formulae is 'Power System Analysis' by J. R. Mortlock and M. W. Humphrey Davies (Chapman & Hall, London); more detailed information on particular types of cables should be obtained direct from the manufacturers.

The equivalent circuit for determining the positive and negative sequence series impedances of a cable is shown in Figure 4.18. From this circuit it can be shown that:

$$Z_1 = Z_2 = \left\{ R_c + R_s \frac{X_{cs}^2}{R_s^2 + X_s^2} \right\} + j \left\{ X_c - X_s \frac{X_{cs}^2}{R_s^2 + X_s^2} \right\} \quad \text{Equation 4.24}$$

where  $R_c$ ,  $R_s$  are core and sheath (screen) resistances per unit length,  $X_c$  and  $X_s$  core and sheath (screen) reactances per unit length and  $X_{cs}$  the mutual reactance between core and sheath (screen) per unit length.  $X_{cs}$  is in general equal to  $X_s$ .

The zero sequence series impedances are obtained directly using Equation 4.11 and account can be taken of the sheath in the same way as an earth wire in the case of an overhead line.

The shunt capacitances of a sheathed cable can be calculated from the simple formula:

$$C = 0.0241 \epsilon \left\{ \frac{1}{\log \frac{d + 2T}{d}} \right\} \mu F/km \quad \text{Equation 4.25}$$

where  $d$  is the overall diameter for a round conductor,  $T$  core insulation thickness and  $\epsilon$  permittivity of dielectric. When the conductors are oval or shaped an equivalent diameter  $d'$  may be used where  $d' = (1/\pi) \times \text{periphery of conductor}$ . No simple formula exists for belted or unscreened cables, but an empirical formula which gives reasonable results is:

$$C = \frac{0.0555 \epsilon}{G} \mu F/km \quad \text{Equation 4.26}$$

where  $G$  is a geometric factor which is a function of core and belt insulation thickness and overall conductor diameter.

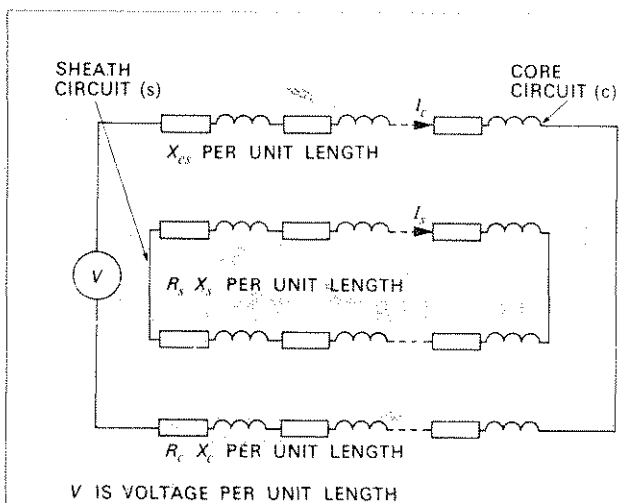


Figure 4.18 Equivalent circuit for determining positive or negative sequence impedance of cables.

|                | Voltage<br>(kV) | ACSR<br>conductor<br>(sq.mm) | ACSR<br>earth<br>wire<br>(sq.mm) | $Z_1$<br>positive<br>sequence<br>impedance<br>(ohms/km) | Circuit<br>layout | Zero sequence<br>impedance<br>angle<br>(degrees)<br>$\rho = 10,000$<br>(ohms/cm <sup>3</sup> ) |
|----------------|-----------------|------------------------------|----------------------------------|---------------------------------------------------------|-------------------|------------------------------------------------------------------------------------------------|
| A              | 11              | 50                           | None                             | 0.65 /35                                                | Single            | /68                                                                                            |
| B              | 11              | 500                          | None                             | 0.28 /75                                                | Single            | /83                                                                                            |
| C              | 33              | 50                           | None                             | 0.69 /40                                                | Single            | /66                                                                                            |
| C <sub>1</sub> | 33              | 50                           | 100                              | 0.69 /40                                                | Single            | /54                                                                                            |
| D              | 33              | 100                          | None                             | 0.53 /55                                                | Single            | /73                                                                                            |
| D <sub>1</sub> | 33              | 100                          | 100                              | 0.53 /55                                                | Single            | /64                                                                                            |
| E              | 33              | 500                          | None                             | 0.35 /81                                                | Single            | /82                                                                                            |
| E <sub>1</sub> | 33              | 500                          | 100                              | 0.35 /81                                                | Single            | /72                                                                                            |
| F              | 33              | 50                           | None                             | 0.52 /54                                                | Double            | /73                                                                                            |
| F <sub>1</sub> | 33              | 50                           | 100                              | 0.52 /54                                                | Double            | /66                                                                                            |

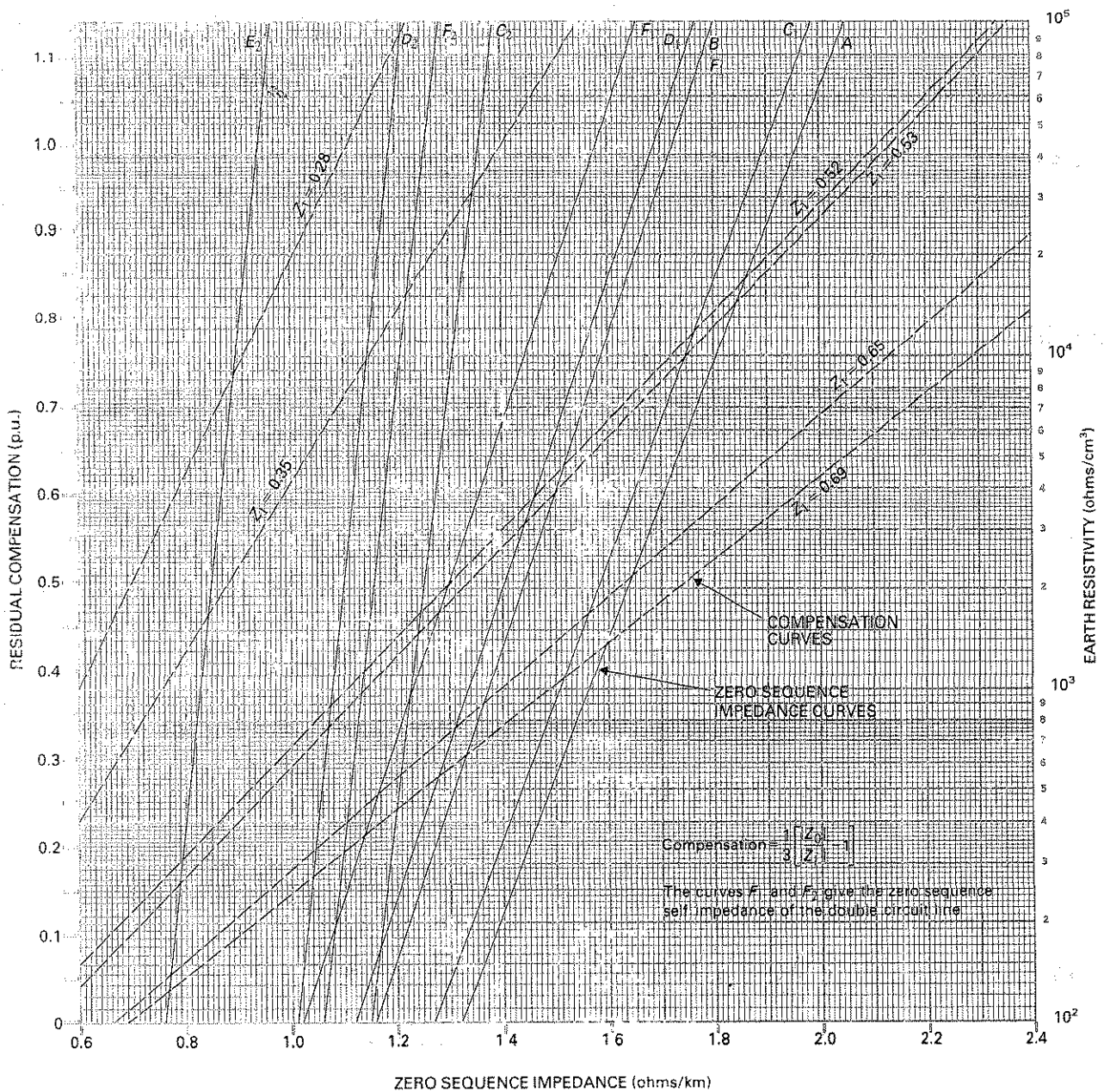


Table 4.6 Residual compensation of distance relays.  
Variations of zero sequence impedance with earth resistivity—O/H lines up to 33kV



|                          | Voltage<br>(kV) | ACSR<br>conductor<br>(sq.mm) | ACSR<br>earth<br>wire<br>(sq.mm) | $Z_1$<br>positive<br>sequence<br>impedance<br>(ohms/km) | Circuit<br>layout | Zero sequence<br>impedance<br>angle<br>(degrees)<br>$\rho = 10,000$<br>(ohms/cm <sup>2</sup> ) |
|--------------------------|-----------------|------------------------------|----------------------------------|---------------------------------------------------------|-------------------|------------------------------------------------------------------------------------------------|
| A }<br>B }<br>C }<br>D } | 66              | 100                          | None                             | 0.52 /54                                                | Double            | /73                                                                                            |
|                          |                 |                              | 100                              | 0.52 /54                                                | Double            | /66                                                                                            |
|                          |                 |                              | None                             | 0.42 /64                                                | Double            | /77                                                                                            |
|                          |                 |                              | One (size<br>unknown)            | 0.42 /64                                                | Double            | /70                                                                                            |
| E }<br>F }               | 66              | 500                          | None                             | 0.33 /81                                                | Double            | /82                                                                                            |
|                          |                 |                              | 100                              | 0.33 /81                                                | Double            | /76                                                                                            |

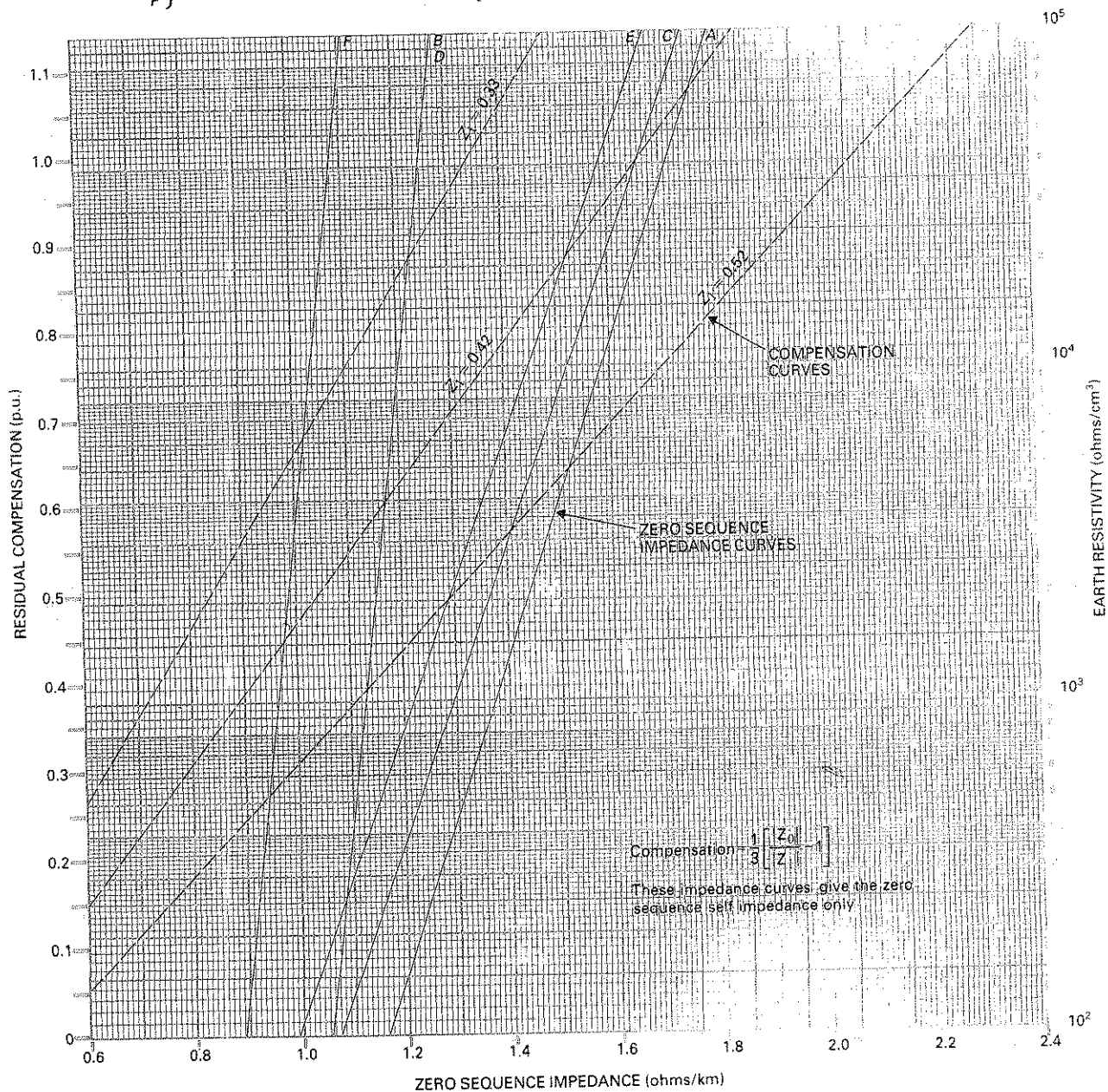


Table 4.7 Residual compensation of distance relays.  
Variations of zero sequence impedance with earth resistivity—O/H lines 66kV

|   | Voltage<br>(kV) | ACSR<br>conductor<br>(sq.mm) | ACSR<br>earth<br>wire<br>(sq.mm) | $Z_1$<br>positive<br>sequence<br>impedance<br>(ohms/km) | Circuit<br>layout | Zero sequence<br>impedance<br>angle<br>(degrees)<br>$\rho = 10,000$<br>(ohms/cm <sup>2</sup> ) |
|---|-----------------|------------------------------|----------------------------------|---------------------------------------------------------|-------------------|------------------------------------------------------------------------------------------------|
| A | 132             | 150                          | None                             | 0.45 /66                                                | Double            | /77                                                                                            |
| B |                 |                              | 70                               | 0.45 /66                                                | Double            | /70                                                                                            |
| C |                 | 175                          | None                             | 0.44 /69                                                | Single            | /78                                                                                            |
| D |                 |                              | 70                               | 0.44 /69                                                | Single            | /78                                                                                            |
| E | 132             | 175                          | None                             | 0.43 /69                                                | Double            | /78                                                                                            |
| F |                 |                              | 70                               | 0.43 /69                                                | Double            | /72                                                                                            |
| G |                 | 500                          | None                             | 0.37 /82                                                | Double            | /82                                                                                            |
| H |                 |                              | 70                               | 0.37 /82                                                | Double            | /77                                                                                            |
| I | 275             | 2 x 175                      | One (size<br>unknown)            | 0.32 /77                                                | Double            | /78                                                                                            |
| J | 275             | 2 x 400                      |                                  | 0.31 /84                                                | Double            | /80                                                                                            |
| K | 400             | 2 x 400                      | 175                              | 0.31 /84                                                | Double            | /80                                                                                            |
| L | 400             | 4 x 400                      | 400                              | 0.27 /86                                                | Double            | /82                                                                                            |

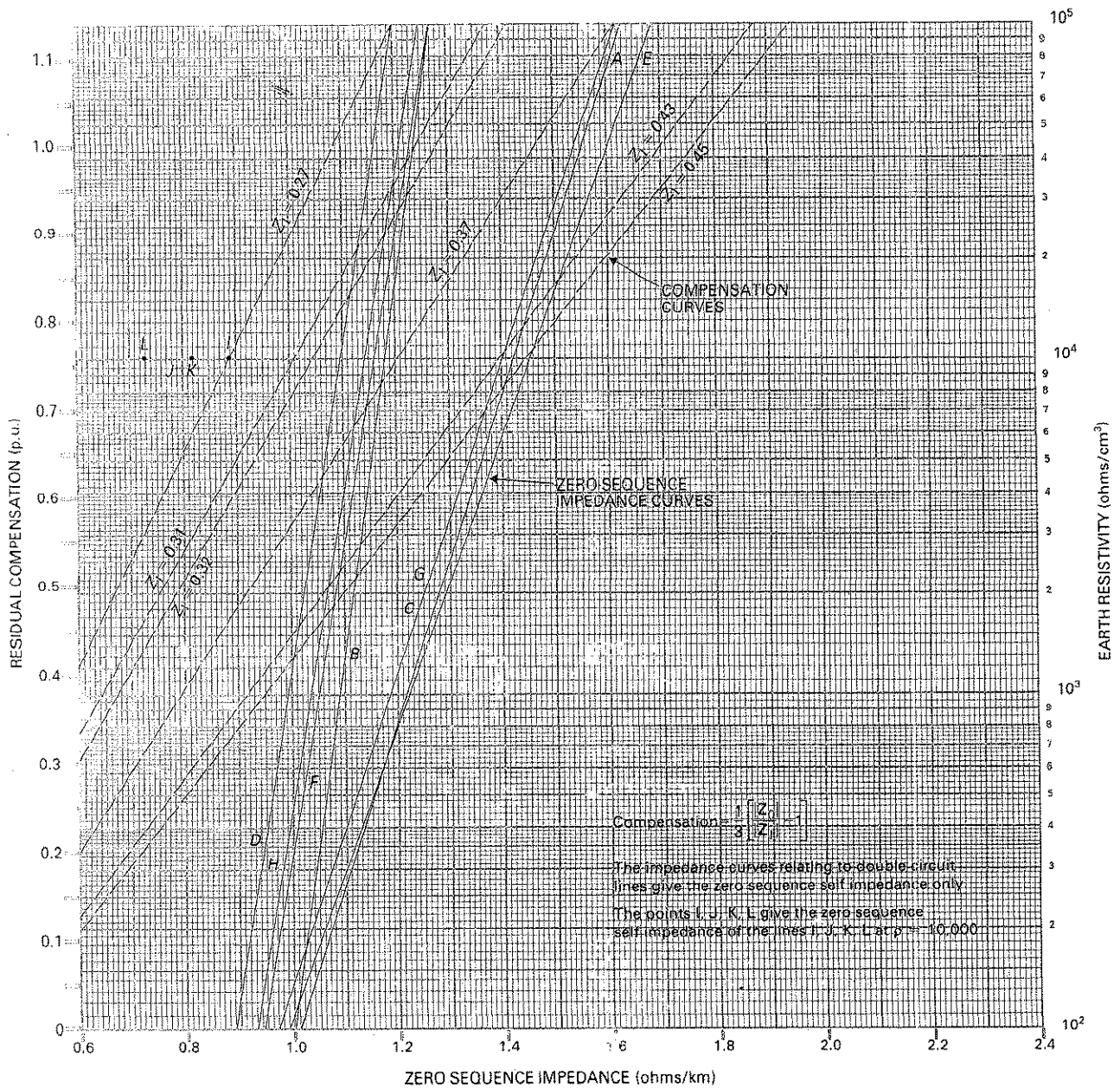


Table 4.8 Residual compensation of distance relays.  
Variations of zero sequence impedance with earth resistivity—O/H lines 132kV and above

## 4.23

### OVERHEAD LINE AND CABLE DATA

The following tables contain data on overhead lines and cables which can be used in conjunction with the various equations quoted in this text.

Table 4.9 GMR for full-stranded copper, aluminium, and aluminium alloy conductors ( $r$  = conductor radius)

| Number of strands | GMR      |
|-------------------|----------|
| 7                 | $0.726r$ |
| 19                | $0.758r$ |
| 37                | $0.768r$ |
| 61                | $0.772r$ |
| 91                | $0.774r$ |
| 127               | $0.776r$ |
| 169               | $0.779r$ |
| Solid             | $0.779r$ |

Table 4.10 GMR for aluminium conductor steel reinforced (ACSR) ( $r$  = conductor radius)

| Number of aluminium strands | Number of layers | GMR      |
|-----------------------------|------------------|----------|
| 6                           | 1                | $0.5r$   |
| 12                          | 1                | $0.75r$  |
| 26                          | 2                | $0.809r$ |
| 30                          | 2                | $0.826r$ |
| 54                          | 3                | $0.810r$ |

NOTE: The values for conductors with one layer of aluminium strands are indicative only. Reactances and consequently the apparent GMRs for such conductors are significantly affected by cyclic magnetic flux which varies with current, temperature and lay of strands. On conductors with multi-layers of aluminium strands the effect is usually negligible.

Table 4.11 GMR<sub>c</sub> of hollow cable conductors

| Internal diameter<br>External diameter | GMR   |
|----------------------------------------|-------|
| 0                                      | 0.780 |
| 0.1                                    | 0.782 |
| 0.2                                    | 0.790 |
| 0.3                                    | 0.810 |
| 0.4                                    | 0.825 |
| 0.5                                    | 0.850 |
| 0.6                                    | 0.876 |
| 0.7                                    | 0.910 |
| 0.8                                    | 0.937 |
| 0.9                                    | 0.970 |
| 1.0                                    | 1.0   |

Table 4.12 Overhead line conductor—hard drawn copper.

| Nominal area    | Stranding and wire diameter | Approx. overall diameter | Calculated d.c. resistance at 20°C per km | Total sectional area |
|-----------------|-----------------------------|--------------------------|-------------------------------------------|----------------------|
| mm <sup>2</sup> | mm                          | mm                       | Ω/km                                      | mm <sup>2</sup>      |
| 10              | 7/1.35                      | 4.05                     | 1.788                                     | 10.02                |
| 14              | 7/1.60                      | 4.80                     | 1.273                                     | 14.07                |
| 16              | 3/2.65                      | 5.69                     | 1.083                                     | 16.54                |
| 25              | 7/2.14                      | 6.42                     | 0.7114                                    | 25.17                |
| 32              | 3/3.75                      | 8.05                     | 0.5410                                    | 33.13                |
| 35              | 7/2.50                      | 7.50                     | 0.5123                                    | 34.36                |
| 50              | 7/3.00                      | 9.00                     | 0.3620                                    | 49.48                |
| 70              | 7/3.55                      | 10.65                    | 0.2585                                    | 69.29                |
| 100             | 7/4.30                      | 12.90                    | 0.1763                                    | 101.65               |
| 125             | 19/2.90                     | 14.50                    | 0.1434                                    | 125.50               |
| 150             | 19/3.20                     | 16.00                    | 0.1178                                    | 152.81               |
| 185             | 18/3.55                     | 17.75                    | 0.09567                                   | 178.16               |

| Nominal aluminium area<br>mm <sup>2</sup> | Stranding and wire diameter |             | Approximate overall diameter<br>mm | Calculated d.c. resistance at 20°C per km<br>Ω | Sectional area of aluminium<br>mm <sup>2</sup> | Total sectional area<br>mm <sup>2</sup> |
|-------------------------------------------|-----------------------------|-------------|------------------------------------|------------------------------------------------|------------------------------------------------|-----------------------------------------|
|                                           | Aluminium<br>mm             | Steel<br>mm |                                    |                                                |                                                |                                         |
| 25                                        | 6/2.36                      | 1/2.36      | 7.08                               | 1.093                                          | 26.24                                          | 30.62                                   |
| 30                                        | 6/2.59                      | 1/2.59      | 7.77                               | 0.9077                                         | 31.61                                          | 36.88                                   |
| 40                                        | 6/3.00                      | 1/3.00      | 9.00                               | 0.6766                                         | 42.41                                          | 49.48                                   |
| 50                                        | 6/3.35                      | 1/3.35      | 10.05                              | 0.5426                                         | 52.88                                          | 61.70                                   |
| 70                                        | 12/2.79                     | 7/2.79      | 13.95                              | 0.3936                                         | 73.37                                          | 116.2                                   |
| 100                                       | 6/4.72                      | 7/1.57      | 14.15                              | 0.2733                                         | 105.0                                          | 118.5                                   |
| 150                                       | 30/2.59                     | 7/2.59      | 18.13                              | 0.1828                                         | 158.1                                          | 194.9                                   |
| 150                                       | 18/3.35                     | 1/3.35      | 16.75                              | 0.1815                                         | 158.7                                          | 167.5                                   |
| 175                                       | 30/2.79                     | 7/2.79      | 19.53                              | 0.1576                                         | 183.4                                          | 226.2                                   |
| 175                                       | 18/3.61                     | 1/3.61      | 18.05                              | 0.1563                                         | 184.3                                          | 194.5                                   |
| 200                                       | 30/3.00                     | 7/3.00      | 21.00                              | 0.1363                                         | 212.1                                          | 261.5                                   |
| 200                                       | 18/3.86                     | 1/3.86      | 19.30                              | 0.1367                                         | 210.6                                          | 222.3                                   |
| 400                                       | 54/3.18                     | 7/3.18      | 28.62                              | 0.06740                                        | 428.9                                          | 484.5                                   |
| 500                                       | 54/3.53                     | 7/3.53      | 31.77                              | 0.05468                                        | 528.7                                          | 597.2                                   |

Table 4.13 Overhead line conductor data—aluminium conductors steel reinforced (ACSR).

| Nominal aluminium area<br>mm <sup>2</sup> | Stranding and wire diameter<br>mm | Approximate overall diameter<br>mm | Calculated d.c. resistance at 20°C per km<br>Ω | Sectional area<br>mm <sup>2</sup> |
|-------------------------------------------|-----------------------------------|------------------------------------|------------------------------------------------|-----------------------------------|
| 25                                        | 7/2.34                            | 7.02                               | 1.094                                          | 30.10                             |
| 30                                        | 7/2.54                            | 7.62                               | 0.9281                                         | 35.47                             |
| 40                                        | 7/2.95                            | 8.85                               | 0.6880                                         | 47.84                             |
| 50                                        | 7/3.30                            | 9.90                               | 0.5498                                         | 59.87                             |
| 100                                       | 7/4.65                            | 13.95                              | 0.2769                                         | 118.9                             |
| 150                                       | 19/3.48                           | 17.40                              | 0.1830                                         | 180.7                             |
| 175                                       | 19/3.76                           | 18.80                              | 0.1568                                         | 211.0                             |
| 300                                       | 37/3.53                           | 24.71                              | 0.09155                                        | 362.1                             |

Table 4.14 Overhead line conductor data—aluminium alloy (BS 3242).

| Nominal aluminium area<br>mm <sup>2</sup> | Stranding and wire diameter<br>mm | Approximate overall diameter<br>mm | Calculated d.c. resistance at 20°C per km<br>Ω | Sectional area<br>mm <sup>2</sup> |
|-------------------------------------------|-----------------------------------|------------------------------------|------------------------------------------------|-----------------------------------|
| 22                                        | 7/2.06                            | 6.18                               | 1.227                                          | 23.33                             |
| 50                                        | 7/3.10                            | 9.30                               | 0.5419                                         | 52.83                             |
| 60                                        | 7/3.40                            | 10.20                              | 0.4505                                         | 63.55                             |
| 100                                       | 7/4.39                            | 13.17                              | 0.2702                                         | 106.0                             |
| 150                                       | 19/3.25                           | 16.25                              | 0.1825                                         | 157.6                             |
| 200                                       | 19/3.78                           | 18.90                              | 0.1349                                         | 213.2                             |
| 250                                       | 19/4.22                           | 21.10                              | 0.1083                                         | 265.7                             |
| 300                                       | 19/4.65                           | 23.25                              | 0.08916                                        | 322.7                             |
| 400                                       | 37/3.78                           | 26.46                              | 0.06944                                        | 415.2                             |

Table 4.15 Overhead line conductor data—standard aluminium.

| Conductor size (sq mm) | 3.3 kV |     | 6.6 kV |     | 11 kV |      | 22 kV |     | 33 kV |      | 66 kV |      | 132 kV |       |
|------------------------|--------|-----|--------|-----|-------|------|-------|-----|-------|------|-------|------|--------|-------|
|                        | % R    | % X | % R    | % X | % R   | % X  | % R   | % X | % R   | % X  | % R   | % X  | % R    | % X   |
| 25                     | 653    | 319 | 163    | 82  | 59    | 30   | 14.6  | 7.8 | 6.5   | 3.6  | —     | —    | —      | —     |
| 50                     | 332    | 302 | 83     | 78  | 30    | 29   | 7.47  | 7.4 | 3.3   | 3.5  | 0.83  | 0.98 | —      | —     |
| 70                     | 237    | 291 | 59     | 76  | 21    | 28   | 5.33  | 7.3 | 2.4   | 3.4  | 0.59  | 0.96 | 0.148  | 0.261 |
| 100                    | 162    | 282 | 40     | 74  | 14.6  | 27   | 3.65  | 7.1 | 1.6   | 3.3  | 0.40  | 0.94 | 0.101  | 0.257 |
| 150                    | 108    | 268 | 27     | 70  | 9.7   | 26   | 2.43  | 6.8 | 1.1   | 3.1  | 0.27  | 0.90 | 0.068  | 0.246 |
| 200                    | 83     | 262 | 21     | 68  | 7.5   | 25.6 | 1.87  | 6.7 | 0.83  | 3.08 | 0.21  | 0.88 | 0.052  | 0.243 |
| 250                    | 65     | 257 | 16     | 67  | 5.9   | 25.1 | 1.46  | 6.5 | 0.65  | 3.00 | 0.16  | 0.87 | 0.041  | 0.239 |
| 300                    | 56     | 251 | 14     | 66  | 5.0   | 24.6 | 1.26  | 6.4 | 0.56  | 2.97 | 0.14  | 0.86 | 0.035  | 0.236 |

Practical mean values of reactance have been assumed in compiling the above data; for aluminium conductors resistance increases by approximately 60 per cent for the same cross section; with equivalent resistance the reactance decreases about 4 per cent.

NOTE: Resistance and reactance per kilometre. Percentage values on 100 MVA basis.

$$\text{Resistance in ohms} = \frac{\%R \times V^2 (\text{kV})}{10,000} \quad \text{Reactance in ohms} = \frac{\%X \times V^2 (\text{kV})}{10,000}$$

Table 4.16 Feeder circuits data—overhead lines

| Line voltage, and equivalent hard drawn copper area (sq. in.) | Number of earth wires | Sequence series impedance (ohms/mile) |                                    |                                            |                                    |                                    |
|---------------------------------------------------------------|-----------------------|---------------------------------------|------------------------------------|--------------------------------------------|------------------------------------|------------------------------------|
|                                                               |                       | $Z_{00}$ (self zero sequence)         |                                    | $Z_{11} = Z_{22}$ (self positive sequence) | $Z_{00'}$ (mutual zero sequence)   |                                    |
|                                                               |                       | $\rho = 10,000 \Omega/\text{cm}^3$    | $\rho = 30,000 \Omega/\text{cm}^3$ |                                            | $\rho = 10,000 \Omega/\text{cm}^3$ | $\rho = 30,000 \Omega/\text{cm}^3$ |
| 33 kV single circuit 0.10                                     | None                  | 2.51 /73.1                            | 2.75 /74.15                        | 0.855 /54.9                                | —                                  | —                                  |
|                                                               | One                   | 1.86 /63.8                            | 1.92 /63.9                         | 0.855 /54.9                                | —                                  | —                                  |
| 66 kV double circuit 0.15                                     | None                  | 2.44 /77.3                            | 2.61 /78.1                         | 0.67 /63.5                                 | 1.60 /81.4                         | 1.76 /82.3                         |
|                                                               | One                   | 1.93 /69.6                            | 2.00 /68.5                         | 0.67 /63.5                                 | 1.07 /69.3                         | 1.15 /67.7                         |
| 66 or 33 kV double circuit 0.10                               | None                  | 2.54 /73.3                            | 2.70 /74.3                         | 0.84 /55.6                                 | 1.60 /81.5                         | 1.77 /82.3                         |
|                                                               | One                   | 1.94 /65.6                            | 2.00 /65.6                         | 0.84 /55.6                                 | 0.97 /71.2                         | 1.03 /71.2                         |
| 132 kV single circuit 0.175                                   | None                  | 2.27 /77.5                            | 2.44 /78.3                         | 0.71 /69                                   | —                                  | —                                  |
|                                                               | One                   | 1.77 /70.9                            | 1.85 /69.9                         | 0.71 /69                                   | —                                  | —                                  |
| 132 kV double circuit 0.175                                   | None                  | 2.30 /77.6                            | 2.46 /78.4                         | 0.70 /68.7                                 | 1.42 /80.4                         | 1.59 /81.4                         |
|                                                               | One                   | 1.86 /71.9                            | 1.94 /71.8                         | 0.70 /68.7                                 | 0.99 /70.9                         | 1.07 /70.8                         |

Values above taken from E.R.A. Technical Report O/T4A

|                                |     |          |   |          |   |   |
|--------------------------------|-----|----------|---|----------|---|---|
| 275 kV double circuit 0.175    | One | 1.44 /78 | — | 0.52 /77 | — | — |
| 275 kV double circuit 0.40     | One | 1.32 /80 | — | 0.50 /84 | — | — |
| 400 kV double circuit 0.40     | One | 1.32 /80 | — | 0.50 /84 | — | — |
| 400 kV double circuit 4 × 0.40 | One | 1.18 /82 | — | 0.44 /86 | — | — |

Table 4.17 Overhead line impedances (ohms/mile) – copper imperial conductors

| Line voltage and ACSR conductor size (sq mm) | Number of earth wires | Sequence series impedance (ohms/km) |                                    |                                            |                                    |                                    |
|----------------------------------------------|-----------------------|-------------------------------------|------------------------------------|--------------------------------------------|------------------------------------|------------------------------------|
|                                              |                       | $Z_{00}$ (self zero sequence)       |                                    | $Z_{11} = Z_{22}$ (self positive sequence) | $Z_{00'}$ (mutual zero sequence)   |                                    |
|                                              |                       | $\rho = 10,000 \Omega/\text{cm}^3$  | $\rho = 30,000 \Omega/\text{cm}^3$ |                                            | $\rho = 10,000 \Omega/\text{cm}^3$ | $\rho = 30,000 \Omega/\text{cm}^3$ |
| 33 kV single circuit 100                     | None                  | 1.56 /73.1                          | 1.71 /74.15                        | 0.53 /54.9                                 | —                                  | —                                  |
|                                              | One                   | 1.16 /63.8                          | 1.19 /63.9                         | 0.53 /54.9                                 | —                                  | —                                  |
| 66 or 33 kV double circuit 100               | None                  | 1.58 /73.3                          | 1.68 /74.3                         | 0.52 /55.6                                 | 0.99 /81.5                         | 1.10 /82.3                         |
|                                              | One                   | 1.21 /65.6                          | 1.24 /65.6                         | 0.52 /55.6                                 | 0.60 /71.2                         | 0.64 /71.2                         |
| 66 kV double circuit 150                     | None                  | 1.52 /77.3                          | 1.62 /78.1                         | 0.42 /63.5                                 | 0.99 /81.4                         | 1.09 /82.3                         |
|                                              | One                   | 1.20 /69.6                          | 1.24 /68.5                         | 0.42 /63.5                                 | 0.66 /69.3                         | 0.71 /67.7                         |

Table 4.18 Overhead line impedances for HV systems with aluminium metric conductors (ohms/km).

| Line voltage.<br>Number of<br>conductors and<br>nominal area<br>(mm <sup>2</sup> ) | Line parameters per km<br>(earth resistivity = 20 ohm metres) |                                     |                                         |                                               |
|------------------------------------------------------------------------------------|---------------------------------------------------------------|-------------------------------------|-----------------------------------------|-----------------------------------------------|
|                                                                                    |                                                               | Zero sequence<br>impedance<br>$Z_0$ | Positive<br>sequence<br>impedance $Z_1$ | Mutual zero<br>sequence<br>impedance $Z_{M0}$ |
| 132 kV                                                                             | ohms                                                          | 0.354 + j1.022                      | 0.177 + j0.402                          | 0.178 + j0.509                                |
| 1 × 175                                                                            | %                                                             | 0.203 + j0.586                      | 0.101 + j0.231                          | 0.102 + j0.292                                |
| 132 kV                                                                             | ohms                                                          | 0.265 + j0.899                      | 0.089 + j0.293                          | 0.177 + j0.511                                |
| 2 × 175                                                                            | %                                                             | 0.152 + j0.516                      | 0.051 + j0.168                          | 0.102 + j0.293                                |
| 132 kV                                                                             | ohms                                                          | 0.191 + j0.963                      | 0.076 + j0.379                          | 0.115 + j0.474                                |
| 1 × 400                                                                            | %                                                             | 0.110 + j0.553                      | 0.044 + j0.218                          | 0.066 + j0.272                                |
| 132 kV                                                                             | ohms                                                          | 0.153 + j0.857                      | 0.038 + j0.281                          | 0.115 + j0.480                                |
| 2 × 400                                                                            | %                                                             | 0.088 + j0.492                      | 0.022 + j0.162                          | 0.066 + j0.275                                |
| 275 kV                                                                             | ohms                                                          | 0.1475 + j0.833                     | 0.0383 + j0.320                         | 0.1096 + j0.445                               |
| 2 × 400                                                                            | %                                                             | 0.0195 + j0.110                     | 0.0051 + j0.042                         | 0.0145 + j0.059                               |
| 275 kV                                                                             | ohms                                                          | 0.1989 + j0.861                     | 0.0888 + j0.316                         | 0.1105 + j0.484                               |
| 2 × 175                                                                            | %                                                             | 0.0263 + j0.114                     | 0.0117 + j0.042                         | 0.0146 + j0.064                               |
| 275 kV                                                                             | ohms                                                          | 0.1575 + j0.929                     | 0.0452 + j0.393                         | 0.1126 + j0.473                               |
| 1 × 700                                                                            | %                                                             | 0.0208 + j0.123                     | 0.0060 + j0.052                         | 0.0149 + j0.063                               |
| 400 kV                                                                             | ohms                                                          | 0.1474 + j0.837                     | 0.0383 + j0.320                         | 0.1095 + j0.448                               |
| 2 × 400                                                                            | %                                                             | 0.0092 + j0.052                     | 0.0024 + j0.020                         | 0.0068 + j0.028                               |
| 400 kV                                                                             | ohms                                                          | 0.1049 + j0.792                     | 0.0192 + j0.278                         | 0.0857 + j0.424                               |
| 4 × 400                                                                            | %                                                             | 0.0065 + j0.049                     | 0.0012 + j0.017                         | 0.0054 + j0.027                               |
| 400 kV                                                                             | ohms                                                          | 0.1075 + j0.820                     | 0.0227 + j0.312                         | 0.0849 + j0.418                               |
| 2 × 700                                                                            | %                                                             | 0.0067 + j0.051                     | 0.0014 + j0.019                         | 0.0053 + j0.026                               |
| 400 kV                                                                             | ohms                                                          | 0.1475 + j0.825                     | 0.0319 + j0.310                         | 0.1160 + j0.447                               |
| 2 × 500                                                                            | %                                                             | 0.0092 + j0.052                     | 0.0020 + j0.019                         | 0.0073 + j0.028                               |

NOTE: Percentage values are at rated voltage on 100 MVA base per circuit.

Table 4.19 Overhead line impedances for EHV systems with aluminium metric conductors (ohms/km)

| Conductor<br>size<br>mm <sup>2</sup> | 3.3 kV |      | 6.6 kV |      | 11 kV |      | 22 kV |      | 33 kV |      | 66 kV* |      | 132 kV* |       |
|--------------------------------------|--------|------|--------|------|-------|------|-------|------|-------|------|--------|------|---------|-------|
|                                      | %R     | %X   | %R     | %X   | %R    | %X   | %R    | %X   | %R    | %X   | %R     | %X   | %R      | %X    |
| 16                                   | 1340   | 94.6 | 335    | 32.4 | 121   | 11.7 | —     | —    | —     | —    | —      | —    | —       | —     |
| 25                                   | 851    | 89.1 | 213    | 30.1 | 76.6  | 10.8 | —     | —    | —     | —    | —      | —    | —       | —     |
| 35                                   | 613    | 82.6 | 153    | 28.0 | 55.2  | 10.1 | —     | —    | —     | —    | —      | —    | —       | —     |
| 50                                   | 453    | 79.9 | 113    | 26.6 | 40.7  | 9.6  | 10.2  | 2.98 | 4.53  | 1.32 | —      | —    | —       | —     |
| 70                                   | 314    | 76.2 | 78.5   | 25.3 | 28.3  | 9.1  | 7.07  | 2.81 | 3.14  | 1.25 | —      | —    | —       | —     |
| 95                                   | 233    | 74.4 | 56.5   | 23.9 | 20.3  | 8.6  | 5.08  | 2.67 | 2.26  | 1.18 | 0.56   | 0.37 | 0.14    | 0.105 |
| 120                                  | 180    | 71.6 | 45.0   | 23.0 | 16.2  | 8.3  | 4.05  | 2.54 | 1.80  | 1.13 | 0.45   | 0.35 | 0.11    | 0.101 |
| 150                                  | 146    | 69.8 | 36.5   | 22.3 | 13.1  | 8.0  | 3.29  | 2.46 | 1.46  | 1.09 | 0.37   | 0.34 | 0.091   | 0.096 |
| 185                                  | 118    | 68.9 | 29.2   | 21.6 | 10.5  | 7.8  | 2.62  | 2.38 | 1.17  | 1.06 | 0.29   | 0.32 | 0.073   | 0.092 |
| 240                                  | 91     | 67.0 | 22.5   | 20.7 | 8.1   | 7.4  | 2.03  | 2.27 | 0.90  | 1.01 | 0.22   | 0.30 | 0.056   | 0.085 |
| 300                                  | 73     | 66.1 | 18.2   | 20.0 | 6.5   | 7.2  | 1.64  | 2.19 | 0.73  | 0.97 | 0.18   | 0.29 | 0.045   | 0.081 |
| *400                                 | 57     | 80.8 | 14.2   | 22.5 | 5.1   | 8.1  | 1.26  | 2.29 | 0.56  | 1.02 | 0.14   | 0.27 | 0.036   | 0.076 |
| *500                                 | 46     | 79.9 | 11.6   | 21.8 | 4.2   | 7.9  | 1.02  | 2.23 | 0.46  | 0.99 | 0.11   | 0.27 | 0.028   | 0.074 |
| *630                                 | 37     | 78.1 | 9.4    | 20.7 | 3.4   | 7.4  | 0.83  | 2.11 | 0.37  | 0.94 | 0.092  | 0.25 | 0.023   | 0.071 |

Cables are of the 3 core type except for those marked \*

NOTE: Resistance and reactance per km. Percentage values on 100MVA basis.

$$\text{Resistance in ohms} = \frac{\% R \times V^2 \text{ (kV)}}{10,000} \quad \text{Reactance in ohms} = \frac{\% X \times V^2 \text{ (kV)}}{10,000}$$

The values above are for copper conductors; for aluminium conductors the resistance increases by 65 percent for the same cross section; with equivalent resistance the reactance decreases about five percent.

Table 4.20 Characteristics of polyethylene insulated cables (XLPE)

| Conductor size<br>mm <sup>2</sup> | 3.3 kV |      | 6.6 kV |      | 11 kV |      | 22 kV |      | 33 kV |      |
|-----------------------------------|--------|------|--------|------|-------|------|-------|------|-------|------|
|                                   | %R     | %X   | %R     | %X   | %R    | %X   | %R    | %X   | %R    | %X   |
| 10                                | 2057   | 87.7 | 514.2  | 26.2 | —     | —    | —     | —    | —     | —    |
| 16                                | 1303   | 83.6 | 326.0  | 24.3 | 111   | 9.26 | —     | —    | —     | —    |
| 25                                | 825.5  | 76.7 | 206.4  | 22.0 | 70.7  | 8.68 | 17.69 | 2.89 | —     | —    |
| 35                                | 595.0  | 74.8 | 148.8  | 21.2 | 60.0  | 8.10 | 12.75 | 2.71 | —     | —    |
| 50                                | 439.9  | 72.5 | 110.0  | 20.4 | 37.7  | 7.81 | 9.42  | 2.60 | 4.19  | 1.16 |
| 70                                | 304.9  | 70.2 | 76.2   | 19.6 | 26.1  | 7.44 | 6.53  | 2.46 | 2.90  | 1.09 |
| 95                                | 220.4  | 67.5 | 55.1   | 18.7 | 18.8  | 7.19 | 4.71  | 2.36 | 2.09  | 1.03 |
| 120                               | 174.5  | 66.6 | 43.6   | 18.3 | 15.0  | 6.90 | 3.74  | 2.25 | 1.66  | 0.98 |
| 150                               | 142.3  | 65.7 | 35.6   | 17.9 | 12.1  | 6.78 | 3.04  | 2.19 | 1.35  | 0.95 |
| 185                               | 113.9  | 64.7 | 28.5   | 17.6 | 9.8   | 6.61 | 2.44  | 2.11 | 1.08  | 0.93 |
| 240                               | 87.6   | 63.8 | 21.9   | 17.1 | 7.5   | 6.45 | 1.87  | 2.04 | 0.83  | 0.89 |
| 300                               | 70.8   | 62.9 | 17.6   | 16.9 | 6.1   | 6.32 | 1.51  | 1.97 | 0.67  | 0.86 |
| 400                               | 56.7   | 62.4 | 14.1   | 16.5 | 4.8   | 6.20 | 1.21  | 1.92 | 0.53  | 0.83 |
| *500                              | 45.5   | 73.5 | 11.3   | 18.8 | 4.0   | 7.02 | 0.96  | 1.90 | 0.43  | 0.90 |
| *630                              | 37.1   | 72.1 | 9.3    | 18.4 | 3.2   | 6.86 | 0.79  | 1.84 | 0.35  | 0.89 |
| *800                              | 31.2   | 71.2 | 7.8    | 18.0 | 2.7   | 6.69 | 0.66  | 1.80 | 0.29  | 0.84 |
| *1000                             | 27.2   | 69.8 | 6.7    | 17.8 | 2.4   | 6.61 | 0.57  | 1.76 | 0.25  | 0.82 |

Cables are of the 3 core type except for those marked \*

NOTE: Resistance and reactance per km. Percentage values on 100 MVA basis.

$$\text{Resistance in ohms} = \frac{\% R \times V^2 (\text{kV})}{10,000}$$

$$\text{Reactance in ohms} = \frac{\% X \times V^2 (\text{kV})}{10,000}$$

Table 4.21 Characteristics of paper insulated cables

| Conductor size<br>mm <sup>2</sup> | 3.3 kV |      |
|-----------------------------------|--------|------|
|                                   | %R     | %X   |
| 16                                | 1267   | 97.3 |
| 25                                | 799    | 91.8 |
| 35                                | 576    | 86.3 |
| 50                                | 425    | 83.6 |
| 70                                | 295    | 79.0 |
| 95                                | 213    | 77.1 |
| 120                               | 169    | 74.4 |
| 150                               | 138    | 72.5 |
| 185                               | 111    | 70.7 |
| 240                               | 85.3   | 69.8 |
| 300                               | 68.9   | 68.9 |
| 400                               | 55.1   | 68.8 |
| *500                              | 45.0   | 81.7 |
| *630                              | 37.6   | 79.0 |
| *800                              | 32.1   | 79.0 |
| *1000                             | 27.5   | 77.1 |

Cables are of the 3 core type except for those marked \*

NOTE Resistance and reactance per km. Percentage values on 100 MVA basis.

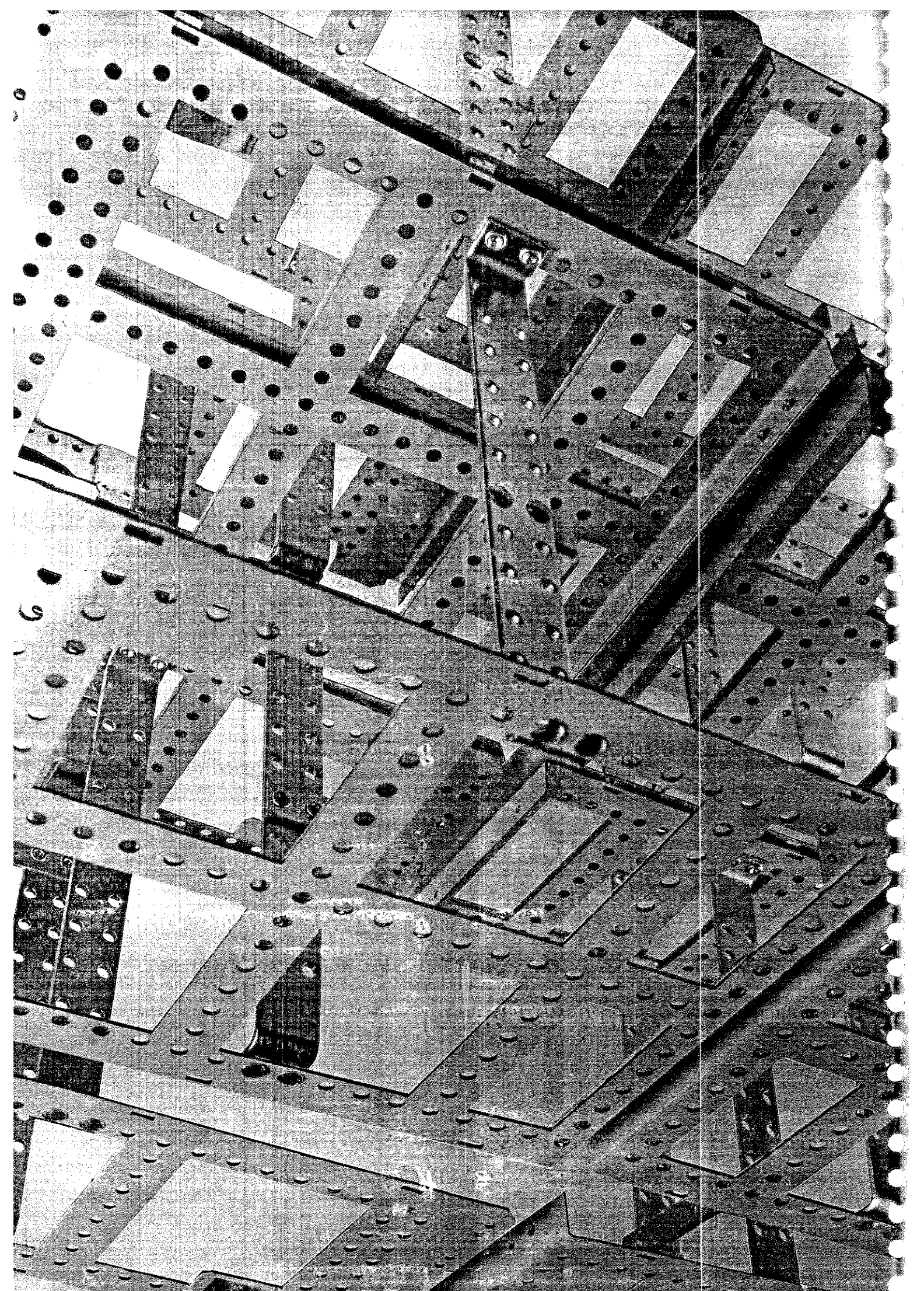
$$\text{Resistance in ohms} = \frac{\% R \times V^2 (\text{kV})}{10,000}$$

$$\text{Reactance in ohms} = \frac{\% X \times V^2 (\text{kV})}{10,000}$$

The values above are for copper conductors; for aluminium conductors the resistance increases by 65 per cent for the same cross section; with equivalent resistance the reactance decreases about 5 per cent.

Table 4.22 3.3 kV PVC insulated cables (BS 6346)







# Current and voltage transformers

- 5.1 Introduction.
- 5.2 Voltage Transformers.
- 5.3 Current Transformers.

## 5.1

Whenever the values of voltage or current in a power circuit are too high to permit convenient direct connection of measuring instruments or relays, coupling is made through transformers. Such 'measuring' transformers are required to produce a scaled down replica of the input quantity to the accuracy expected for the particular measurement; this is made possible by the high efficiency of the transformer. The performance of measuring transformers during and following large instantaneous changes in the input quantity is important, in that this quantity may depart from the sinusoidal waveform. The deviation may consist of a step change in magnitude, or a transient component which persists for an appreciable period, or both. The resulting effect on instrument performance is usually negligible, although for precision metering a persistent change in the accuracy of the transformer may be significant.

However, many protective systems are required to operate in a time shorter than the period of transient disturbance in the output of the measuring transformers that follows a system fault. The errors in transformer output may abnormally delay the operation of the protection, or cause unnecessary operations. The functioning of such transformers must, therefore, be examined analytically.

Consideration is first given to a simple transformer, without reference to its application, as indicated in Figure 5.1.

If the primary winding is energized while the secondary circuit is open-circuited the transformer will become, in effect, an iron-cored inductor and will present a relatively high impedance.

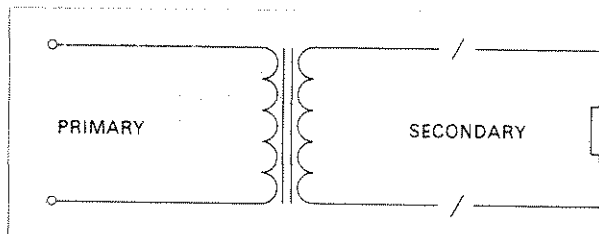


Figure 5.1 Basic transformer circuit

A current will flow and a voltage drop will develop across the winding in proportion to its impedance. The current will be entirely expended in magnetizing the CT core.

The voltage drop in the primary winding occurs because of the electro-motive force induced in this winding by the flux in the core, and a corresponding e.m.f. is induced in the secondary winding, which links with the same flux.

If the circuit of the secondary winding is closed through an impedance a proportionate current will flow; this current produces an m.m.f. which, by Lenz's Law, must be opposed to the flux. The tendency for the flux to be reduced by this demagnetizing force, combined with the corresponding reduction of the primary back e.m.f., will cause an increase in the primary current. If the primary winding had no losses and the applied voltage were maintained constant, the primary back e.m.f., and therefore also the core flux, would be maintained at the initial value, and the increase in primary m.m.f. would be identical to that of the secondary winding.

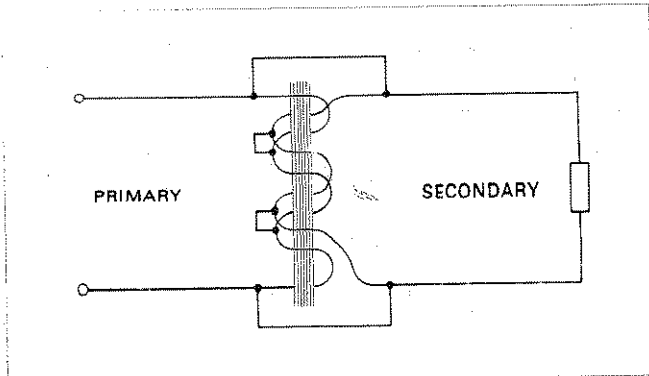


Figure 5.2 Derivation of equivalent circuit—simple transformer.

Figure 5.2 shows a transformer composed of two equal closely coupled windings surrounding a common core.

Since identical electro-motive forces are induced in each winding it is possible to represent the windings as being connected together at multiple points so that they become in effect one. The circuit can be shown as in Figure 5.3, the load being supplied from the power source in parallel with the exciting impedance of the transformer.

In practice the primary winding will have some resistance and may possess additional reactance due to flux which does not link the secondary winding. In consequence, the secondary winding m.m.f. is not exactly balanced by an equivalent increase in primary m.m.f.

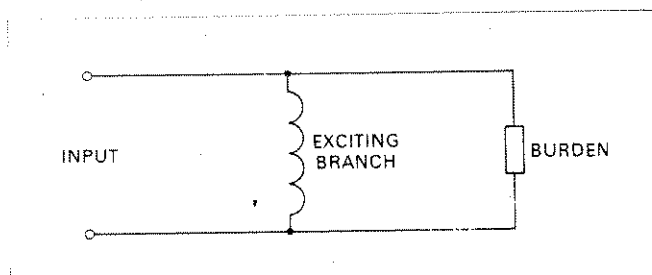


Figure 5.3 Derivation of equivalent circuit—burden and exciting branch.

For this reason the main flux is slightly weakened, reducing the primary back e.m.f. by an amount sufficient to allow the extra current to flow through the winding resistance and leakage reactance. This is fairly represented by putting the winding resistance and leakage reactance in the input leads.

In the same way secondary leakage impedance can be regarded as being additional to the connected load impedance and is represented by a suitable value of impedance in the output leads. The shunt exciting impedance has been treated as pure reactance; core losses can be included by connecting a resistance of an appropriate value in parallel with the magnetizing reactance.

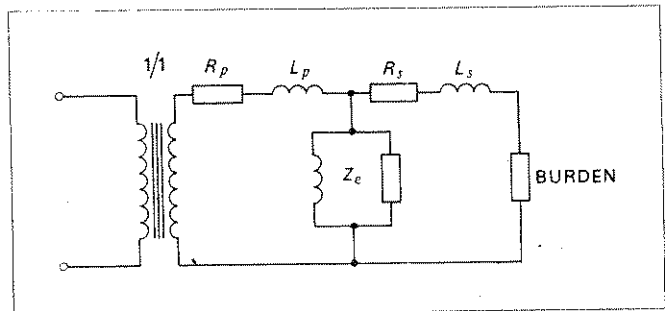
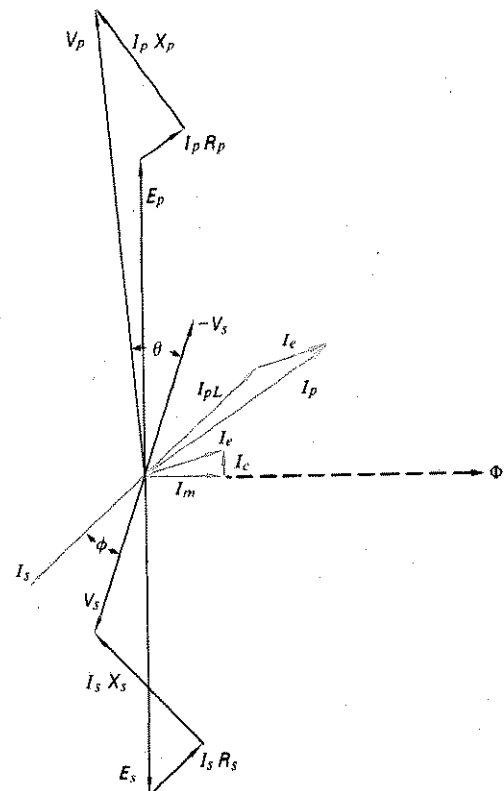


Figure 5.4 Equivalent circuit of transformer.

The complete equivalent circuit now appears as shown in Figure 5.4. When the transformer is not 1/1 ratio the condition can be represented by energizing the equivalent circuit with an ideal transformer of the given ratio but having no losses.



- $V_p$  = Primary applied voltage
- $E_p$  = Primary induced e.m.f.
- $V_s$  = Secondary output voltage
- $E_s$  = Secondary induced e.m.f.
- $\Phi$  = Flux
- $I_e$  = Exciting current
- $I_m$  = Magnetizing component
- $I_c$  = Iron loss component
- $\theta$  = Phase angle error
- $\phi$  = Secondary burden angle
- $I_p R_p$  = Primary resistance voltage drop
- $I_p X_p$  = Primary reactance voltage drop
- $I_s R_s$  = Secondary resistance voltage drop
- $I_s X_s$  = Secondary reactance voltage drop
- $I_s$  = Secondary current
- $I_{pL}$  = Load component of primary current
- $I_p$  = Primary current

Figure 5.5 Vector diagram for voltage transformer.

### 5.1.1

#### Measuring transformers

Voltage and current transformers for low primary voltage or current ratings are not readily distinguishable; for higher ratings, dissimilarities of construction are usual. Nevertheless the differences between these devices lie principally in the way they are connected into the power circuit. Voltage transformers are connected across the points at which the voltage is to be measured, and are therefore much like small power transformers, differing only in details of design which control ratio accuracy over the specified range of output. Current transformers have their primary windings connected in series with the power circuit, and so also in series with the system impedance. As in an ammeter, the primary winding input impedance is low, the current being controlled almost entirely by the primary system impedance. The response of the transformer is radically different in these two modes of operation.

### 5.2

#### PROTECTIVE VOLTAGE TRANSFORMERS

In the shunt mode, the system voltage is applied across the input terminals of the equivalent circuit of Figure 5.4. The vector diagram for this circuit is shown in Figure 5.5.

The secondary output voltage  $V_s$  is required to be an accurate scaled replica of the input voltage  $V_p$  over a specified range of output. To this end the winding voltage drops are made small, and the normal flux density in the core is designed to be well below the saturation density, in order that the exciting current may be low and the exciting impedance substantially constant with a variation of applied voltage over the desired operating range including some degree of overvoltage. These limitations in design result in a VT for a given burden being much larger than a typical power transformer of similar rating. The exciting current, in consequence, will not be as small, relative to the rated burden, as it would be for a typical power transformer.

### 5.2.1

#### Errors

The designer calculates the voltage and phase errors of voltage transformers from the known constants of the core and windings by analyzing the vector diagram of Figure 5.5.

The ratio error is defined as:

$$\frac{K_n V_s - V_p}{V_p} \times 100\%$$

where  $K_n$  is the nominal ratio and  $V_p$  and  $V_s$  are the actual primary and secondary terminal voltages. If the error is positive, the secondary voltage exceeds the nominal value. The turns ratio of the transformer need not be equal to the nominal ratio; a small turns compensation will usually be employed, so that the error will be positive for low burdens and negative for high burdens.

The phase error is the phase difference between the reversed secondary and the primary voltage vectors. It is positive when the reversed secondary voltage leads the primary vector. Requirements in this respect are set out in BS 3941: 1975. All voltage transformers are required to comply with one of the classes in Table 5.1.

For protective purposes, accuracy of voltage measurement may be important during fault conditions, as the system voltage might be reduced by the fault to a low value. Voltage transformers for such types of service must comply with the extended range of requirements set out in Table 5.2.

| Accuracy Class | 0.8 to 1.2 times rated voltage<br>0.25 to 1.0 times rated burden at 0.8 power factor |                              |
|----------------|--------------------------------------------------------------------------------------|------------------------------|
|                | Voltage ratio error (per cent)                                                       | Phase displacement (minutes) |
| 0.1            | $\pm 0.1$                                                                            | $\pm 5$                      |
| 0.2            | $\pm 0.2$                                                                            | $\pm 10$                     |
| 0.5            | $\pm 0.5$                                                                            | $\pm 20$                     |
| 1.0            | $\pm 1.0$                                                                            | $\pm 40$                     |
| 3.0            | $\pm 3.0$                                                                            | Not specified                |

Table 5.1 Limits of error for measuring voltage transformers.

| Accuracy Class | 0.25 to 1.0 times rated burden at<br>0.8 power factor<br>0.05 to $V_f$ times rated<br>primary voltage |                              |
|----------------|-------------------------------------------------------------------------------------------------------|------------------------------|
|                | Voltage ratio error (per cent)                                                                        | Phase displacement (minutes) |
| 3P             | $\pm 3$                                                                                               | $\pm 120$                    |
| 6P             | $\pm 6$                                                                                               | $\pm 240$                    |

Table 5.2 Additional limits for protective voltage transformers.

### 5.2.2

#### Voltage factors

The quantity  $V_f$  in Table 5.2 is an upper limit of operating voltage, expressed per unit of rated voltage, which may be important for correct relay operation and may also be important when the ability of the VT to withstand the condition is being considered. Earth faults cause a displacement of the system neutral, particularly in the case of unearthed or impedance earthed systems, resulting in a rise in the voltage on the un-faulted phases.

Voltage factors, with the permissible duration of the maximum voltage, are given in Table 5.3

| Voltage factor $V_f$ | Time rating | Method of connecting the primary winding and system earthing conditions                                                                                              |
|----------------------|-------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1.2                  | Continuous  | Between lines in any network.<br>Between transformer star-point and earth in any network                                                                             |
| 1.2                  | Continuous  | Between line and earth in an effectively earthed neutral system                                                                                                      |
| 1.5                  | 30s         |                                                                                                                                                                      |
| 1.2                  | Continuous  | Between line and earth in a non-effectively earthed neutral system with automatic earth fault tripping.                                                              |
| 1.9                  | 3Cs         |                                                                                                                                                                      |
| 1.2                  | Continuous  | Between line and earth in an isolated neutral system without automatic earth fault tripping, or in a resonant earthed system without automatic earth fault tripping. |
| 1.9                  | 8h          |                                                                                                                                                                      |

Table 5.3 Maximum voltage permissible duration.

### 5.2.3

#### Secondary leads

Voltage transformers are designed to maintain the specified accuracy in voltage output at their secondary terminals and it has been seen that this is achieved by designing the winding impedances to be suitably low. It will be clear that the use of long secondary leads, which introduce a further voltage drop, can destroy the accuracy of the voltage output as received at the switchboard.

The obvious solution is to fit a distribution box close to the VT and supply relay and metering burdens over separate leads. If necessary, allowance can be made for the resistance of the leads to individual burdens when the particular equipment is calibrated.

#### 5.2.4

#### Protection of voltage transformers

Voltage transformers can be protected by H.R.C. fuses on the primary side for voltages up to 66kV. Fuses do not usually have a sufficient interrupting capacity for use with higher voltages.

Voltage transformers should always be protected by secondary fuses, or by a miniature circuit breaker which should be located as near to the transformer as possible. A short circuit on the secondary circuit wiring will produce a current of many times the rated output; this is a natural consequence of the low regulation necessary to maintain ratio accuracy over the range of rated burden. Although a VT will usually carry, without overheating, a current considerably in excess of its rating, the short-circuit current would certainly cause excessive heating. Even where primary fuses can be fitted, these will usually not clear a secondary side short circuit because of the low value of primary current and the minimum practicable fuse rating.

#### 5.2.5

#### Construction

The construction of a voltage transformer differs from that of a power transformer only in so far as different emphasis is placed on cooling, insulation and mechanical design. The rated output seldom exceeds a few hundred VA, and therefore the heat normally generated presents no problem.

The size of a VT is largely determined by the system voltage, the insulation of the primary winding often exceeding in volume the winding itself.

A VT should be insulated to withstand overvoltages, including impulse voltages, of a level equal to the withstand value of the switchgear and the high voltage system. To achieve this in a compact design, the voltage must be distributed uniformly across the winding, which requires uniform distribution of the winding capacitance or the application of electrostatic shields.

Voltage transformers are commonly used in association with switchgear, so the physical design must be compact and adapted for mounting on to or in conjunction with the switchgear in question. Three-phase units are common up to 36kV but for higher voltages single-phase units are more suitable.

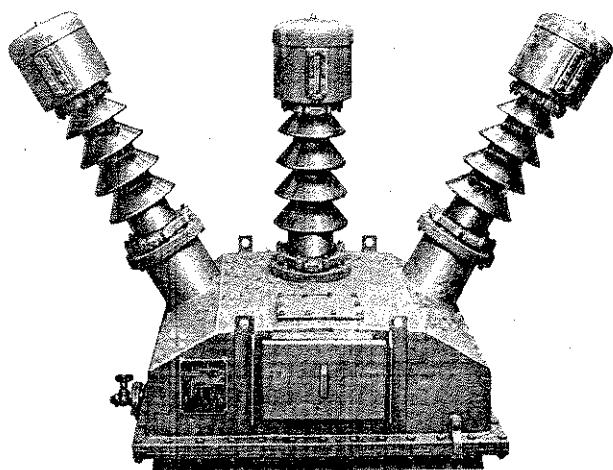


Figure 5.6 Typical 36kV three-phase voltage transformer.

Voltage transformers for medium voltage circuits will have dry type insulation, but for high and extra high voltage systems oil immersed units are general. Resin encapsulated designs are in use on systems up to 33kV.

Figures 5.6 to 5.12 show a selection of voltage transformers for high voltage systems.

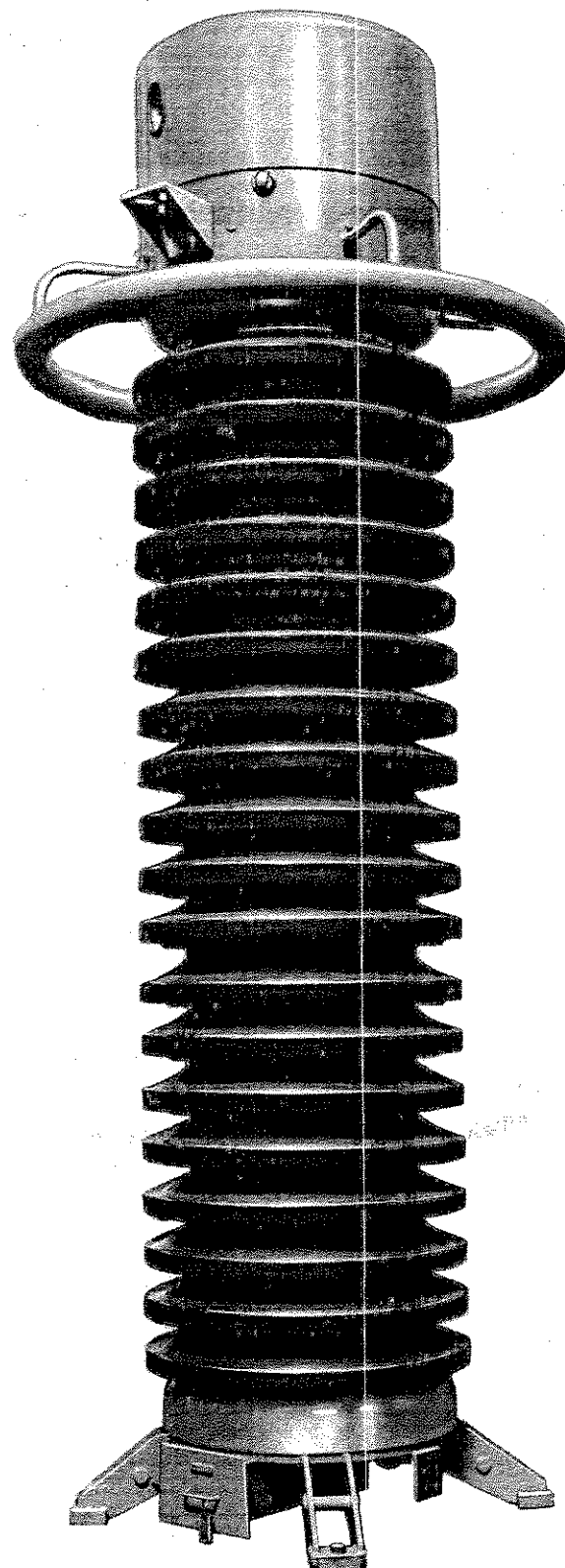


Figure 5.7 Three stage 420kV electromagnetic cascade voltage transformer.

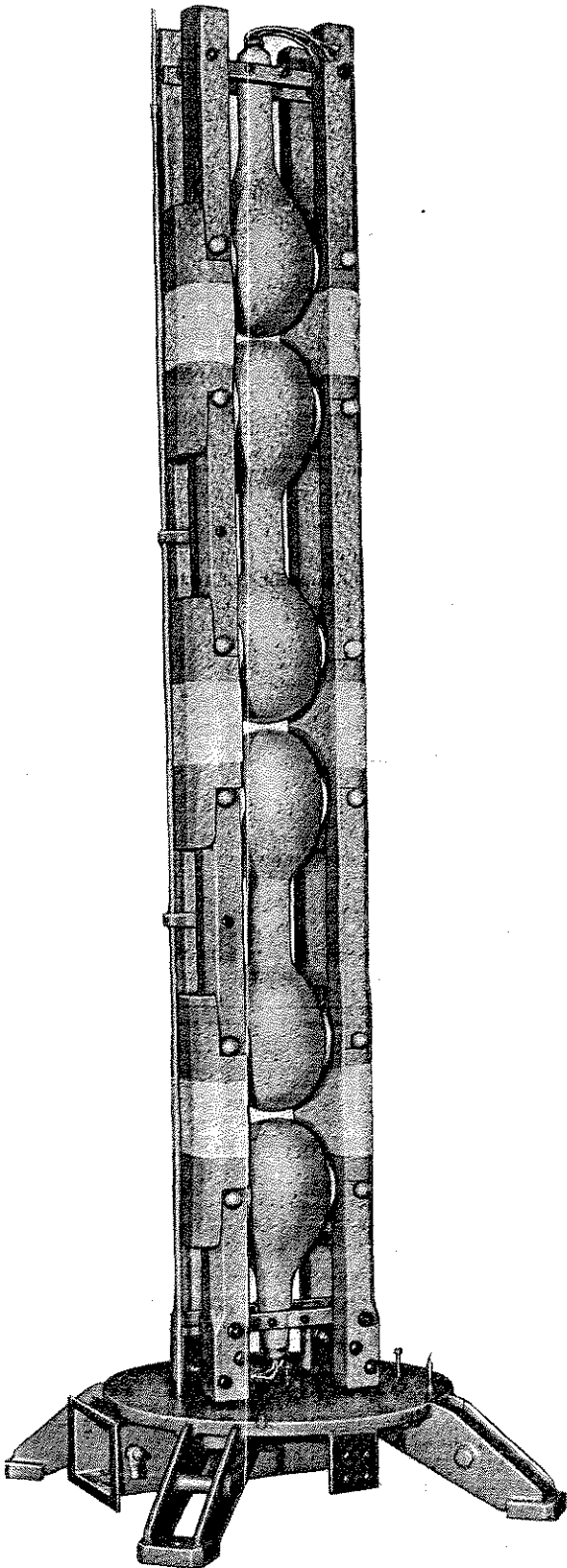


Figure 5.8 Core and winding assembly of three stage 420kV electromagnetic cascade voltage transformer.

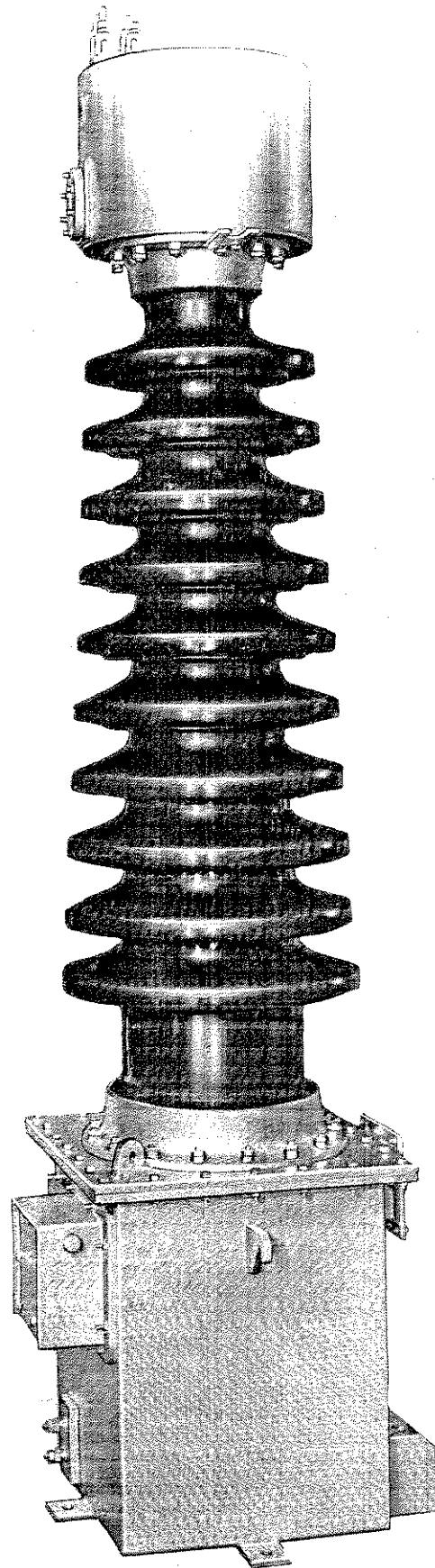


Figure 5.9 Single stage 145kV electromagnetic voltage transformer.

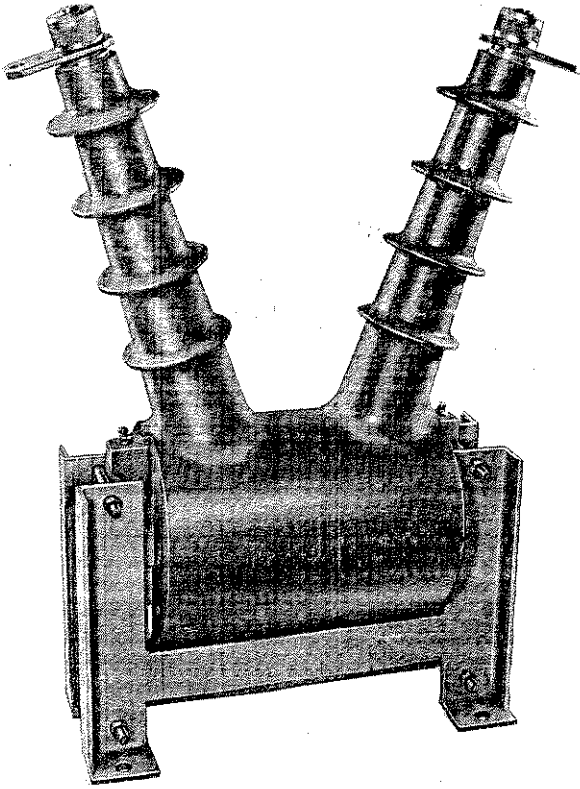


Figure 5.10 Single-phase 17.5kV cast-in-resin voltage transformer.

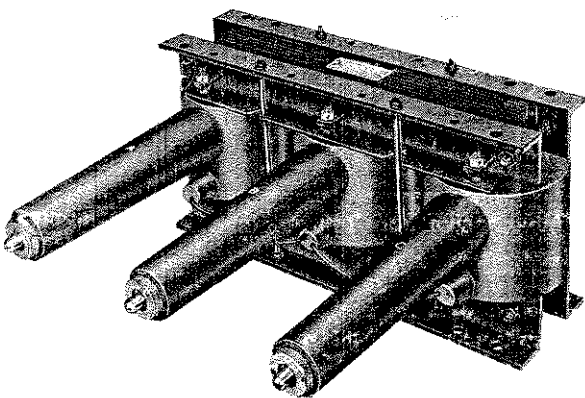


Figure 5.11 Three-phase 12kV cast-in-resin voltage transformer.

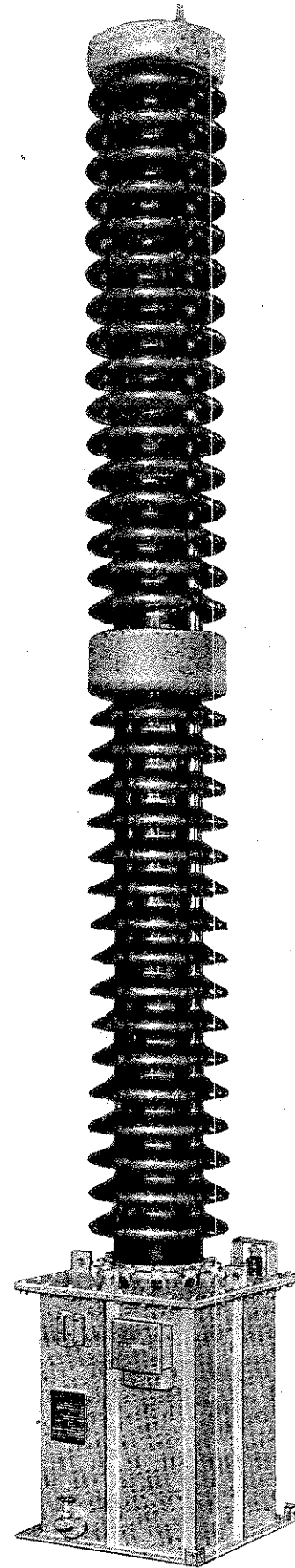


Figure 5.12 Single-phase 345kV capacitor voltage transformer.

### 5.2.6

#### Residually connected voltage transformers

The three voltages of a balanced system summate to zero, but this is not so when the system is subject to a single-phase earth fault. The residual voltage which exists in this case is significant in protective gear practice as a means of detecting earth fault conditions. The residual voltage of a system is measured by connecting the primary windings of a three-phase VT between the three phases and earth and connecting the secondary windings in series or 'broken delta' as shown in Figure 5.13.

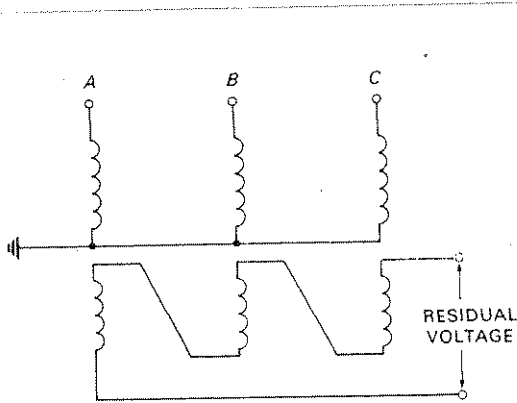


Figure 5.13 Residual voltage connection.

The output of the secondary windings connected in broken delta is zero when balanced sinusoidal voltages are applied, but under conditions of imbalance any residual voltage of the system will be developed.

The residual voltage is three times the zero sequence voltage. In order to measure this component, it is necessary for a zero sequence flux to be set up in the VT, and for this to be possible there must be a return path for the resultant summated flux. It is therefore necessary for the VT core to have one or more unwound limbs linking the yokes in addition to the limbs carrying windings. Usually the core is made symmetrically, with five limbs, the two outermost ones being unwound.

This consideration does not arise when three single-phase units are used, as is common for EHV systems, since each phase unit will have a core with a closed magnetic circuit.

It is equally necessary for the primary winding neutral to be earthed, for without an earth zero sequence exciting current cannot flow.

If the primary winding is not earthed, an open-delta winding may develop a voltage but this will be entirely third harmonic. A sinusoidal e.m.f. requires a third harmonic component in the exciting current, which for a three-phase transformer is a zero sequence component. If, owing to the lack of a neutral-earth connection, no path exists for this the flux wave will contain a third harmonic component with a corresponding third harmonic in the electro-motive forces in the primary and secondary windings. The open delta e.m.f. so produced is not related to any residual voltage in the primary system.

The possible increase of the voltage of unfaulted phases during earth faults should also be borne in mind and a VT to be used in this way should be rated to have an appropriate voltage factor as described in Section 5.2.2 and Table 5.3.

Voltage transformers are often provided with a normal star-connected secondary winding and a broken-delta connected 'tertiary' winding. Alternatively the residual voltage can be extracted by using a star/broken-delta connected group of auxiliary voltage transformers energized from the secondary winding of the main unit. For this to be

successful, the main voltage transformer must fulfil all the requirements for handling a zero sequence voltage; that is, it must be of five-limb construction, have an earthed primary neutral and be rated for a suitable voltage factor. The star points of the main VT secondary winding and the auxiliary VT primary winding must be interconnected to complete the zero sequence circuit, and the auxiliary VT must also be suitable for the appropriate voltage factor.

It should be noted that third harmonics in the primary voltage wave, which are of zero sequence, summate in the broken-delta winding.

### 5.2.7

#### Transient performance

Transient errors cause few difficulties in the use of conventional voltage transformers although some do occur.

If a voltage is suddenly applied, an inrush transient will occur, as with power transformers. The effect will, however, be less severe than for power transformers because of the lower flux density for which the VT is designed; if the VT is rated to have a fairly high voltage factor, little inrush effect will occur. An error will appear in the first few cycles of the output current in proportion to the inrush transient that occurs.

When the supply to a voltage transformer is interrupted, the core flux will not readily collapse; the secondary winding will tend to maintain the magnetizing force to sustain this flux, and will circulate a current through the burden which will decay more or less exponentially, possibly with a superimposed audio-frequency oscillation due to the capacitance of the winding. Bearing in mind that the exciting quantity, expressed in ampere-turns, may exceed the burden, the transient current may be significant.

### 5.2.8

#### Capacitor voltage transformers

The size of electromagnetic voltage transformers for the higher voltages is largely proportional to the rated voltage; the cost tends to increase at a disproportionate rate. An alternative and more economic solution has been found in the capacitor voltage transformer.

This device is basically a capacitance potential divider. As with resistance-type potential dividers, the output voltage is seriously affected by load at the tapping point; in effect, the two portions of the divider, considered in parallel, can be treated as a source impedance, causing a voltage regulation drop when load current is taken. The capacitance divider differs in that its equivalent source impedance is capacitive and can therefore be compensated by a reactor connected in series with the tapping point. With an ideal reactor, such an arrangement would have no regulation and could supply any value of output.

A reactor is never ideal, however, always possessing some resistance, which limits the output that can be obtained. If the divider reduced the system voltage to the usual value of 63.5 volts (phase to neutral), the capacitors would have to be very large to permit a normal value of output to be taken with errors within the usual limits. For a given value of high voltage capacitor, more output is obtained by choosing a higher tapping point voltage, which voltage can then be transformed to the usual value using a relatively inexpensive transformer. The successive stages of this reasoning are indicated in Figure 5.14.

There are numerous variations of this basic circuit. The inductance  $L$  may be a separate unit or it may be incorporated in the form of leakage reactance in the transformer  $T$ . Because the capacitors  $C_1$  and  $C_2$  cannot conveniently be made to close tolerances, it is necessary to provide adjustment of ratio by tapings, either on the transformer  $T$ , or on a separate auto-transformer in the secondary circuit. Adjustment of the tuning inductance  $L$  is also needed; this can be done with tapings, a separate tapped inductor



in the secondary circuit, by adjustment of gaps in the iron cores, or by shunting with variable capacitance.

A simplified equivalent circuit is shown in Figure 5.15, in which  $C$  is equal to  $C_1 + C_2$  (Figure 5.14(c)),  $L$  is the tuning inductance and  $R_p$  represents the resistance of the primary winding of transformer  $T$ ,  $Z_e$  is the exciting impedance of transformer  $T$ ,  $R_s$  the secondary circuit resistance, and  $Z_b$  the burden impedance, all impedances being referred either to the intermediate voltage or to the secondary voltage.

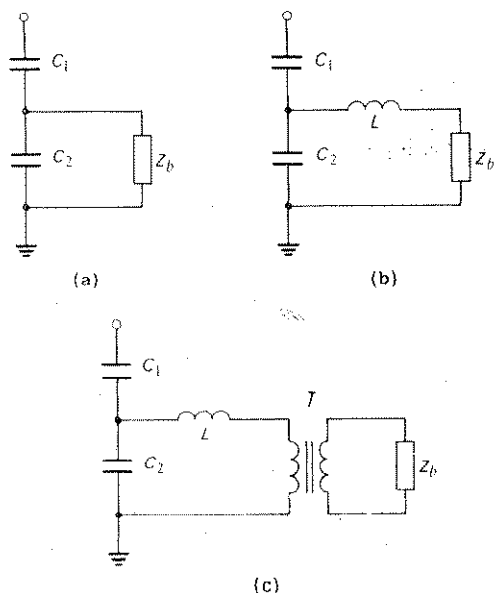


Figure 5.14 Development of capacitor voltage transformer.

It will be seen that the basic difference between Figure 5.15 and Figure 5.4 is the presence of  $C$  and  $L$ . At normal frequency when  $C$  and  $L$  are in resonance and therefore cancel, the circuit behaves in a similar manner to a conventional VT. At other frequencies, however, a reactive component exists which modifies the errors. In British practice the limits of errors are specified for unity power factor burdens. This results in phase error change with frequencies deviating from normal. Provided that the reactive voltages across  $C$  and  $L$  are not too large in relation to  $V_p$ , the change of error with frequency is not excessive. For a typical design, in which  $C_1$  has the value 2000 pF and  $V_1$  has the value 12kV, the change in phase error, with 150VA u.p.f. output, per Hz of frequency change (in the region of rated frequency) is about:

40 minutes for 145kV capacitor voltage transformers  
20 minutes for 300kV capacitor voltage transformers  
14 minutes for 420kV capacitor voltage transformers

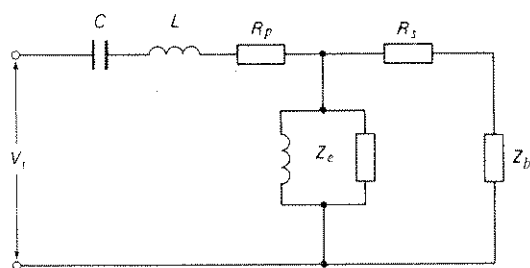


Figure 5.15 Simplified equivalent circuit of capacitor voltage transformer.

To reduce cost, capacitor voltage transformers have been designed which have a relatively high regulation with variation of burden, and which in consequence have to be adjusted, by selection of taps, to suit the actual burden imposed. Provided that the burden remains constant, the VT will meet the accuracy requirements.

Alternatively, a VT can be of the 'full-range' type; these will comply with the appropriate limits of error of their declared accuracy class over a range of output of 25% to 100% of rated output without adjustment to the setting of the electromagnetic unit. Such a VT is naturally larger and more expensive than the type requiring adjustment according to burden.

### 5.2.9

#### Voltage protection of auxiliary capacitor

The capacitor VT, as shown above, is essentially a series resonant circuit in series with the burden impedance. Although this resonant circuit presents little source impedance, the voltage drop on the reactor (and the corresponding voltage change at the stack tapping point) increases in proportion to the output current which is drawn. If the burden impedance were to be short-circuited, the rise in the reactor voltage would be limited only by the reactor losses and possible saturation, that is, to  $Q \times E_2$  where  $E_2$  is the no-load stack tapping point voltage and  $Q$  is the amplification factor of the resonant circuit. This value would be excessive and is therefore limited by a spark gap connected across the auxiliary capacitor. The voltage on the auxiliary capacitor is higher at full rated output than at no load, and the capacitor is rated for continuous service at this raised value. The spark gap will be set to flash over at about twice the full load voltage.

The effect of the spark gap is to limit the short-circuit current which the VT will deliver and fuse protection of the secondary circuit has to be carefully designed with this point in mind. Facilities are usually provided to earth the tapping point, either manually or automatically, before making any adjustments to tappings or connections.

### 5.2.10

#### Transient behaviour of capacitor voltage transformers

A capacitor VT is a series resonant circuit as shown in the developing circuits of Figure 5.14. The introduction of the electromagnetic transformer between the intermediate voltage and the output makes possible further resonance involving the exciting impedance of this unit and the capacitance of the divider stack. When a sudden voltage step is applied, oscillations in line with these different modes take place, and will persist for a period governed by the total resistive damping that is present. Any increase in resistive burden reduces the time constant of a transient oscillation, although the chance of a larger initial amplitude is increased.

With the small units with tapping adjustments, it was general practice to compensate reactive burdens to unity power factor, since this made possible easier adjustment of the errors by tap selection on the tuning reactor and transformer.

While a resistive burden helps to damp out transient oscillations, a compensated reactive burden constitutes a further tuned circuit and introduces new modes of oscillation, which can persist for several cycles of the system frequency. It is now standard practice, when using the modern larger capacitor voltage transformers which do not require adjustment according to burden, not to compensate for any inductive burdens which may be applied.

For very high speed protection, transient oscillations should be minimized. Modern capacitor voltage transformers are much better in this respect than their earlier



counterparts, but high performance protection schemes are still be adversely affected.

### 5.2.11 Ferro-resonance

The exciting impedance  $Z_e$  of the auxiliary transformer  $T$  and the capacitance of the potential divider together form a resonant circuit which will usually oscillate at a sub-normal frequency. If this circuit is subjected to a voltage in phase, which may be no more than the switching on of the supply voltage, some degree of oscillation will ensue, which, because of the non-linear nature of the inductance, may pass through a range of frequencies. If the basic frequency of this circuit is slightly less than one-third of the system frequency, it is possible for energy to be absorbed from the system and cause the oscillation to build up. As this happens, increasing flux density in the transformer core reduces the inductance, bringing the resonant frequency nearer to the one-third value of the system frequency. The result is a progressive build-up until the oscillation stabilizes as a third sub-harmonic of the system, which can be maintained indefinitely. Depending on the values of components, oscillations at fundamental frequency or at other sub-harmonics or multiples of the supply frequency are possible but the third sub-harmonic is the one most likely to be encountered. The principal manifestation of such an oscillation is a rise in output voltage, the r.m.s. value being perhaps 25 to 50 per cent above the normal value; the output waveform would generally be of the form shown in Figure 5.16.

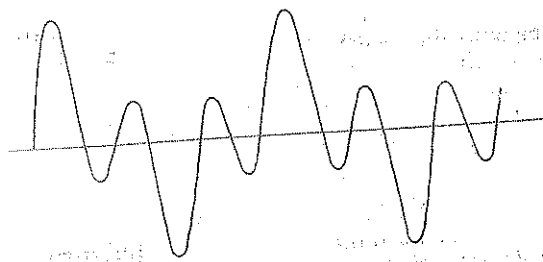


Figure 5.16 Typical secondary voltage waveform with third sub-harmonic oscillation.

Such oscillations are less likely to occur when the circuit losses are high, as is the case with a resistive burden, and if trouble of this nature is encountered it can be prevented by increasing the resistive burden.

Special anti-ferro-resonance devices that use a parallel-tuned circuit are sometimes built into the VT. Although such arrangements help to suppress ferro-resonance, they tend to impair the transient response, so that the design is a matter of compromise.

Correct design will prevent a CVT that supplies a resistive burden from exhibiting this effect, but it is possible for non-linear inductive burdens, such as auxiliary voltage transformers, to induce ferro-resonance. Auxiliary voltage transformers for use with capacitor voltage transformers should be designed with a low value of flux density (about 0.4 webers/m<sup>2</sup> in silicon steel cores), which prevents transient voltages from causing core saturation, which in turn would bring high exciting currents.

### 5.2.12

#### Cascade voltage transformers

The capacitor VT was developed because of the high cost of conventional electromagnetic voltage transformers but, as shown in Section 5.2.8, the frequency and transient responses are less satisfactory than those of the orthodox voltage transformers. Another solution to the problem is the cascade VT.

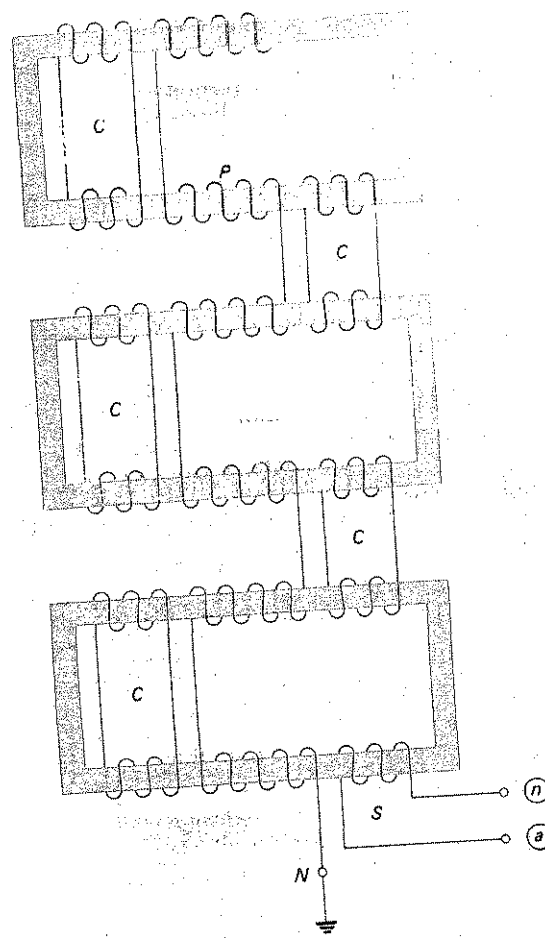


Figure 5.17 Schematic diagram of typical cascade voltage transformer.

The conventional type of VT has a single primary winding, the insulation of which presents a great problem for voltages above about 132kV. The cascade VT avoids these difficulties by breaking down the primary voltage in several distinct and separate stages.

The complete VT is made up of several individual transformers, the primary windings of which are connected in series, as shown in Figure 5.17.

Each magnetic core has primary windings (P) on two opposite sides. The secondary winding (S) consists of a single winding on the last stage only. Coupling windings (C), connected in pairs between stages, provide low impedance circuits for the transfer of load ampere-turns between stages and ensure that the power frequency voltage is equally distributed over the several primary windings.

The potentials of the cores and coupling windings are fixed at definite values by connecting them to selected points on the primary windings. The insulation of each winding need only be enough for the voltage developed in that winding, which is a fraction of the total according to the number of stages. The individual transformers are mounted on a structure built of insulating material, which provides the interstage insulation, accumulating to a value able to withstand the full system voltage across the complete height of the stack. The entire assembly is contained in a hollow cylindrical porcelain housing with external weather-sheds; the housing is filled with oil and sealed, a cushion of nitrogen being included to permit expansion with temperature change.

### 5.3 CURRENT TRANSFORMERS

The primary winding of a current transformer is connected in series with the power circuit; the impedance of the transformer, with secondary burden connected, is negligible compared with that of the power circuit. Even with the secondary circuit open the resulting higher input impedance is still small enough to be neglected. So the power system impedance, even on short circuit, governs the current passing through the primary winding of the current transformer. The condition can be represented by inserting the load impedance, referred through the turns ratio, in the input connection of Figure 5.4.

This approach is developed below, in Figure 5.18, taking the numerical example of a 300/5 ampere CT applied to an 11kV power system. The system is considered to be carrying rated current (300A) and the CT is feeding a burden of 10VA.

Figure 5.18(a) shows the actual arrangement. Figure 5.18(b) shows an equivalent circuit in which the primary e.m.f. energizes the load through a hypothetical 'ideal' transformer that has no losses, representing the ratio transformation only. The losses of the actual transformer are represented by an equivalent circuit similar to that of Figure 5.4, fed by the ideal transformer. In Figure 5.18(c), the primary quantities have been referred to the secondary side by multiplying the primary circuit e.m.f. by the turns ratio  $r$  and multiplying the primary circuit impedance by  $r^2$ .

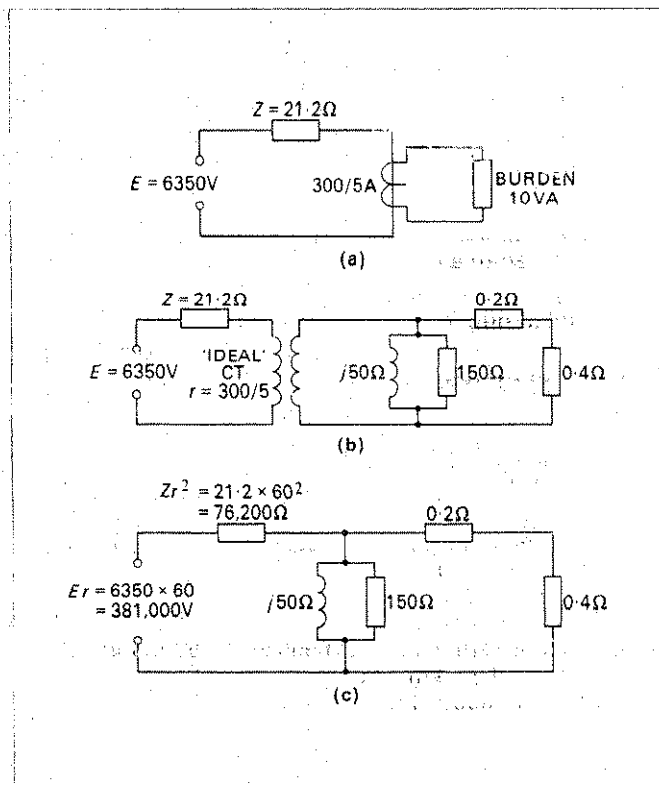


Figure 5.18 Derivation of equivalent circuit of a current transformer.

A study of the final equivalent circuit of Figure 5.18(c), taking note of the typical component values, will reveal all the properties of a current transformer; it will be seen that:

- The secondary current will not be affected by change of the burden impedance over a considerable range.
- The secondary circuit must not be interrupted while the primary winding is energized, since, if the secondary circuit is broken, the e.m.f. induced in the secondary winding will be high enough to present a danger to life and insulation. The voltage developed will be that due to the entire primary current passing through the magnetizing impedance which normally is very high.

c. The ratio and phase angle errors can be calculated easily if the magnetizing characteristics and the burden impedance are known.

#### 5.3.1 Errors

The general vector diagram (Figure 5.5) can be simplified by the omission of details which are not of interest in current measurement; see Figure 5.19. It will be seen from Figure 5.19 that errors arise because of the shunting of the burden by the exciting impedance. This uses a small portion of the input current for exciting the core, reducing the amount passed to the burden. So  $I_s = I_p - I_e$ , where  $I_e$  is dependent on the secondary e.m.f.  $E_s$  given by the equation  $E_s = I_s(Z_s + Z_b)$ , and on  $Z_e$  the exciting impedance.  $Z_s$  is the self-impedance of the secondary winding, which can generally be taken as the resistive component  $R_s$  only;  $Z_b$  is the impedance of the burden.  $I_p$  is the referred value of primary current applied to the equivalent circuit.

#### Current or ratio error

This is the difference in magnitude between  $I_p$  and  $I_s$ , and is equal to  $I_e$ , the component of  $I_e$  which is in phase with  $I_s$ .

#### Phase error

$I_q$ , the component of  $I_e$  in quadrature with  $I_s$ , results in the phase error  $\theta$ .

The values of the current error and phase error depend on the phase displacement between  $I_s$  and  $I_e$  but neither current nor phase error can exceed the vectorial error  $I_e$ . It will be seen that with a moderately inductive burden, with  $I_s$  and  $I_e$  approximately in phase, there will be little phase error and the exciting component will result almost entirely in current error.

#### 5.3.2 Turns compensation

A reduction of the secondary winding by one or two turns is often used to compensate for the small current error introduced by component  $I_e$ . The prospective secondary current is then slightly high, but is reduced by the current error due to the exciting component, with the result that the actual current error may be very small. For example, in the CT corresponding to Figure 5.18, the worst error due to the use of an inductive burden of rated value would be about 1.2%. If the nominal turns ratio is 2:120, removal of one secondary turn would raise the output by 0.83% leaving the overall current error as -0.37%.

For lower value burden or other burden power factor the error would change in the positive direction to a maximum of +0.7% at zero burden; the leakage reactance of the secondary winding is assumed to be negligible.

No corresponding correction can be made for phase error, but it should be noted that the phase error is small for moderately reactive burdens.

#### 5.3.3 Composite error

This is defined in BS 3938:1973 as the r.m.s. value of the difference between the ideal secondary current and the actual secondary current; it includes current and phase errors and the effects of harmonics in the exciting current. In a CT with a negligible leakage flux and no turns correction, 'composite error' corresponds to the r.m.s. value of the exciting current, usually expressed as a percentage of the primary current.

If the exciting impedance were in fact linear, the vectorial error  $I_e$  (Figure 5.19) would be the composite error. In practice the exciting impedance is non-linear, with the result that the exciting current contains some harmonics

| Class | ± percentage current (ratio) error at percentage of rated current shown below |                            |               | Phase displacement at percentage of rated current shown below in minutes |                            |               |
|-------|-------------------------------------------------------------------------------|----------------------------|---------------|--------------------------------------------------------------------------|----------------------------|---------------|
|       | 10 up to but not incl. 20                                                     | 20 up to but not incl. 100 | 100 up to 120 | 10 up to but not incl. 20                                                | 20 up to but not incl. 100 | 100 up to 120 |
| 0.1   | 0.25                                                                          | 0.2                        | 0.1           | 10                                                                       | 8                          | 5             |
| 0.2   | 0.5                                                                           | 0.35                       | 0.2           | 20                                                                       | 15                         | 10            |
| 0.5   | 1                                                                             | 0.75                       | 0.5           | 60                                                                       | 45                         | 30            |
| 1     | 2                                                                             | 1.5                        | 1             | 120                                                                      | 90                         | 60            |

Table 5.4 Limits of error for accuracy classes 0.1 to 1.

which increase its r.m.s. value and thus increase the composite error. This effect is most noticeable in the region approaching saturation of the core.

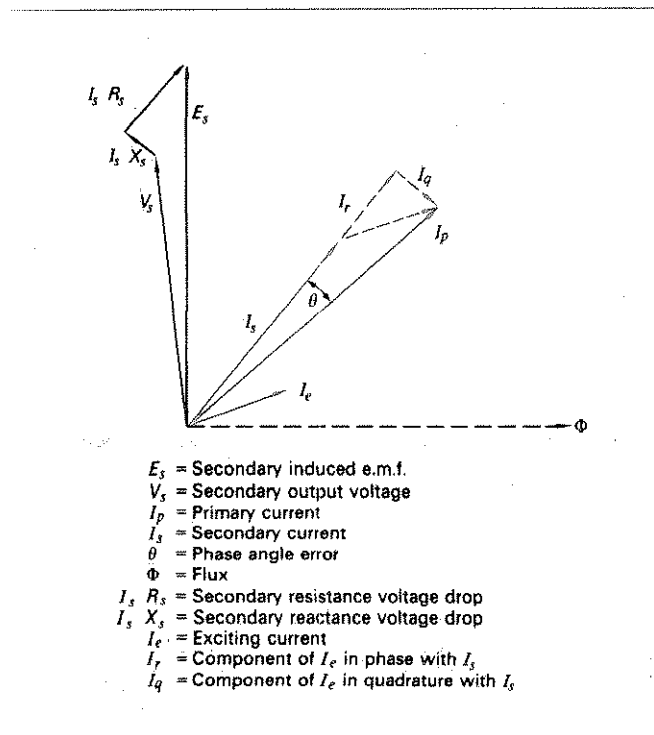


Figure 5.19 Vector diagram for current transformer.

The accuracy class of measuring current transformers used in British practice, in accordance with BS 3938:1973, is shown in Tables 5.4 and 5.5.

| Class | ± percentage current (ratio) error at percentage of rated current shown below |     |
|-------|-------------------------------------------------------------------------------|-----|
|       | 50                                                                            | 120 |
| 3     | 3                                                                             | 3   |
| 5     | 5                                                                             | 5   |

NOTE. Limits of phase displacement are not specified for class 3 and class 5.

Table 5.5 Limits of error for accuracy class 3 and class 5.

For classes 0.1 to 1 the current error and phase displacement at rated frequency shall not exceed the values given in Table 5.4 when the secondary burden is any value from 25% to 100% of the rated burden.

For class 3 and class 5 the current error at rated frequency shall not exceed the values given in Table 5.5 when the secondary burden is any value from 50% to 100% of the rated burden.

The secondary burden used for test purposes shall have a power factor of 0.8 lagging, except that where a burden is less than 5VA a power factor of 1.0 shall be used. In no case shall the test burden be less than 1VA.

### 5.3.4

#### Accuracy limit current of protective current transformers

Protective equipment is intended to respond to fault conditions, and is for this reason required to function at current values above the normal rating. Current transformers for this application must retain a reasonable accuracy up to the largest relevant current. This value is known as the 'accuracy limit current' and may be expressed in primary or equivalent secondary terms. The ratio of the accuracy limit current to the rated current is known as the 'accuracy limit factor'.

The accuracy class of protective current transformers used in British practice, in accordance with BS 3938:1973, is further shown in Table 5.6.

| Class | Current error at rated primary current (per cent) | Phase displacement at rated current (minutes) | Composite error at rated accuracy limit primary current (per cent) |
|-------|---------------------------------------------------|-----------------------------------------------|--------------------------------------------------------------------|
| 5P    | ± 1                                               | ± 60                                          | 5                                                                  |
| 10P   | ± 3                                               |                                               | 10                                                                 |

Standard accuracy limit factors are 5, 10, 15, 20 and 30.

Table 5.6 Limits of error for accuracy class 5P and class 10P.

For class 5P and class 10P the current error, the phase displacement and the composite error (at rated frequency) shall not exceed the values given in Table 5.6 when the secondary burden is 100% of rated burden.

For test purposes, when the current error and phase displacement are being determined, the burden shall have a power factor of 0.8 lagging, except that where the burden is less than 5VA a power factor of 1.0 is permissible.

Even though the burden of a protective CT is only a few VA at rated current, the output required from the CT may be considerable if the accuracy limit factor is high. For example, with a factor of 30 and a burden of 10VA, the CT may have to supply 9000VA to the secondary circuit.

Alternatively, the same CT may be subjected to a high burden. For overcurrent and earth fault protection, with elements of similar VA consumption at setting, an earth fault element set at 10% would have 100 times the impedance of the overcurrent elements set at 100%. Although saturation of the relay elements somewhat modifies this aspect of the matter, it will be seen that the earth fault element is a severe burden, and the CT is likely to have a considerable ratio error in this case. So it is not much use applying turns compensation to such current transformers; it is generally simpler to wind the CT with turns corresponding to the nominal ratio.

Current transformers are often used for the dual duty of measurement and protection. They will then need to be rated according to a class selected from both Tables 5.4 and 5.6. The applied burden is the total of instrument and relay burdens. Turns compensation may well be needed to achieve the measurement performance. Measurement ratings are expressed in terms of rated burden and class, for

example 15VA Class 0.5. Protective ratings are expressed in terms of rated burden, class, and accuracy limit factor, for example 10VA Class 10P10.

### 5.3.5

#### Class X current transformers

The classification of Table 5.6 is only really useful for overcurrent protection.

Guidance is given in BS3938 to the application of current transformers to earth fault protection, but for this and for the majority of other protection applications it is better to refer directly to the maximum useful e.m.f. which can be obtained from the CT. In this context, the 'knee-point' of the excitation curve is defined as 'that point at which a further increase of 10% of secondary e.m.f. would require an increment of exciting current of 50%'; see Figure 5.20.

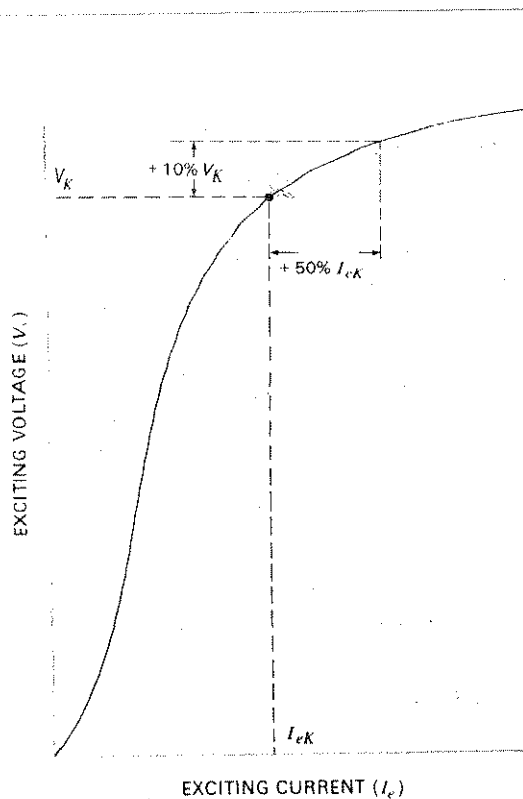


Figure 5.20 Definition of knee-point of excitation curve.

Design requirements for current transformers for general protective purposes are frequently laid out in terms of knee-point e.m.f., exciting current at the knee-point (or some other specified point) and secondary winding resistance. Such current transformers are designated Class X.

### 5.3.6

#### CT winding arrangements

##### Wound primary type

A CT has been treated above as being of conventional construction. This is true for auxiliary current transformers and for many low or moderate ratio current transformers for use in switchgear of up to 11kV rating. Such current transformers differ from ordinary transformer construction only in that the primary winding conductor is of large section, being designed to carry the short-circuit current of the system. The design may be based on the windings developing typically 400 ampere-turns at rated current so that a CT of 100/5 ampere rating might have 4 primary turns and 80 secondary turns (neglecting turns compensation).

##### Bushing or bar primary type

Many current transformers have a ring-shaped core, sometimes built up from annular stampings, but often consisting of a single length of strip tightly wound to form a close-turned spiral.

The secondary winding forms a toroid which should occupy the whole perimeter of the core, a small gap being left between start and finish leads for insulation. If the winding requires more than one layer of wire, each layer should be complete. If, however, the number of turns of adequate wire gauge would not occupy a whole layer, the turns may be spaced slightly apart so that the winding can be uniformly distributed.

Such current transformers normally have a single concentrically placed primary conductor, sometimes permanently built into the CT and provided with the necessary primary insulation, but very often the bushing of a circuit breaker or power transformer is used for this purpose.

At low primary current ratings it may be difficult to obtain sufficient output at the desired accuracy not only because a large core section is needed to provide enough flux to induce the secondary e.m.f. in the small number of turns, but also because the exciting ampere-turns form a large proportion of the primary ampere-turns available. This effect is particularly pronounced when the core diameter has been made large so as to fit over large EHV bushings.

##### Core-balance current transformers

The core-balance CT is normally of the ring type, through the centre of which is passed the three-core cable, or three single-core cables, of a three-phase system. An earth fault relay, connected to the secondary winding, is energized only when there is residual current in the primary system.

The advantage is using this method of earth fault protection lies in the fact that only one CT core is used in place of the conventional three phase-CT's whose three secondary windings are residually connected. In this way the CT magnetizing current at relay operation is reduced by approximately three-to-one, an important consideration in sensitive earth fault relays where a low effective setting is required. Furthermore the number of secondary turns does

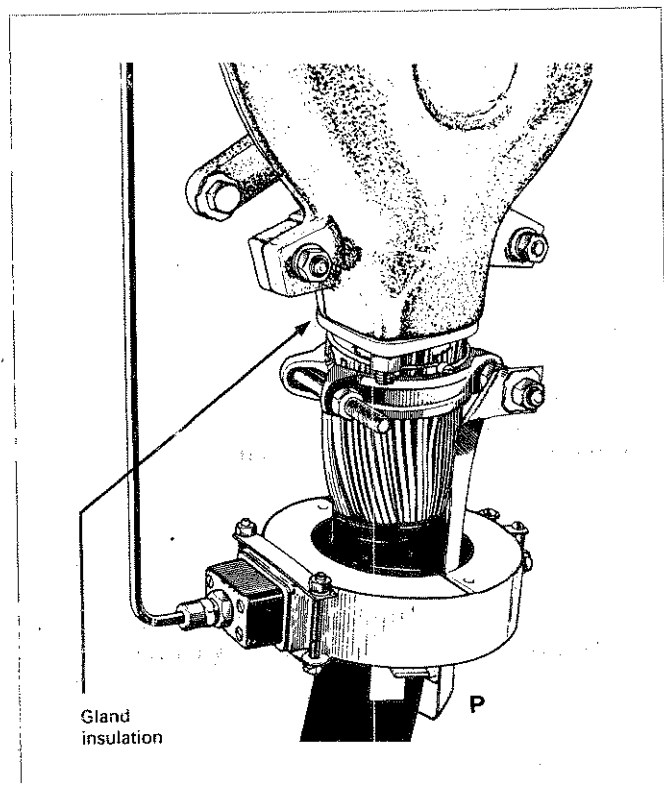


Figure 5.21 Method of connecting earth bonding strip.

not need to be related to the cable rated current because no secondary current would flow under normal balanced conditions. This allows the number of secondary turns to be chosen such as to optimize the effective primary pick-up current.

Core-balance transformers are normally mounted over a cable at a point close up to the cable gland of switchgear or other apparatus. Physically split cores, that is 'slip-over' types, are normally available for applications in which the cables are already made up, as on existing switchgear.

Preferably glands of the insulated type should be used on the main plant involved, with connections as shown in Figure 5.21. The cable sheath could be earthed on the side of the CT remote from the cable gland, that is, at point P in Figure 5.21. However the connections shown in the illustration whereby the earth connection is taken at the cable gland and brought back through the CT aperture results in protection against earth faults right up to the cable gland.

Where insulated type cable glands have not been installed in the switchgear, as may occur in existing power plant, it is necessary to interrupt the lead-covering or steel-wire armouring of the cable as the latter passes through the core-balance transformer. Continuity of the earth path provided by the cable sheath is then restored via an interconnecting earth conductor passing outside the core-balance CT.

#### Summation current transformers

The summation arrangement is a winding arrangement used in a measuring relay or on an auxiliary current transformer to give a single phase output signal having a specific relationship to the three-phase current input.

A more complete account is given in Section 10.6.

#### Air-gapped current transformers

These are auxiliary current transformers in which a small air gap is included in the core to produce a secondary voltage output proportional in magnitude to current in the primary winding. Sometimes termed 'transactors' or 'quadrature current transformers', this form of current transformer has been used as an auxiliary component of unit protection schemes in which the outputs into multiple secondary circuits must remain linear for and proportioned to the widest practical range of input currents.

Types of line current transformer having both larger and smaller gaps in their cores are described in following sections.

#### Overdimensioned current transformers

It has been shown in Section 5.3.12 that current transformers which are capable of correctly transforming fully offset short-circuit currents are, in general, extremely bulky. This type of current transformer is referred to as the 'overdimensioned' type and possesses the most faithful transformation properties of all continuous core CT's. It does however make large demands on the mounting space available in current transformer housings.

In common with other conventional iron core current transformers, the overdimensioned CT is prone to transformation errors due to remanent core flux caused by previous heavy current conditions. This remanent flux may have a value up to 90% of that corresponding to the saturation level.

#### Anti-remanence current transformers

A variation in the overdimensioned class of current transformer has small gap(s) in the core magnetic circuit, thus reducing the possible remanent flux from approximately 90% of saturation value to some 10% only. These gap(s) are quite small, for example 0.12mm total, and so the

excitation characteristic is not significantly changed by their presence. However, the resulting decrease in possible remanent core flux confines any subsequent d.c. flux excursion, resulting from primary current asymmetry, to

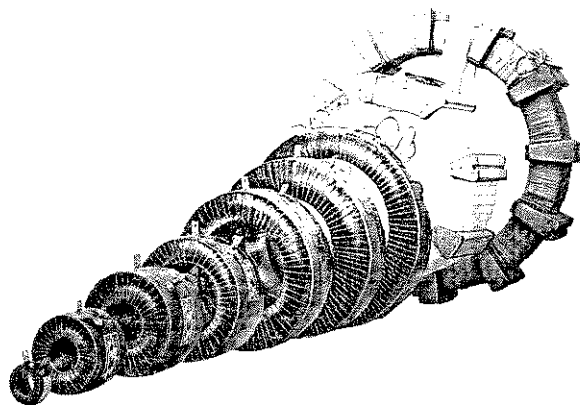


Figure 5.22 Ring type current transformers.

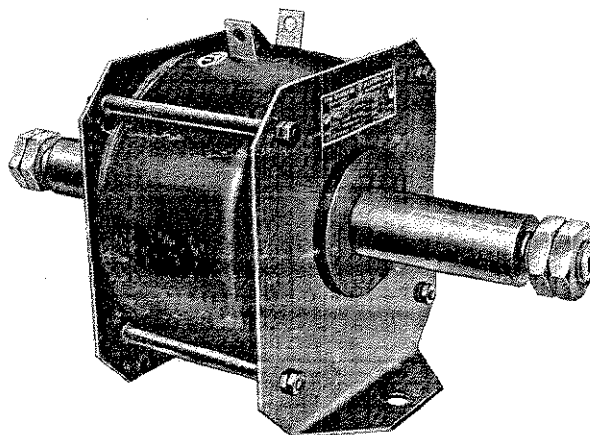


Figure 5.23 Bar primary type current transformer.

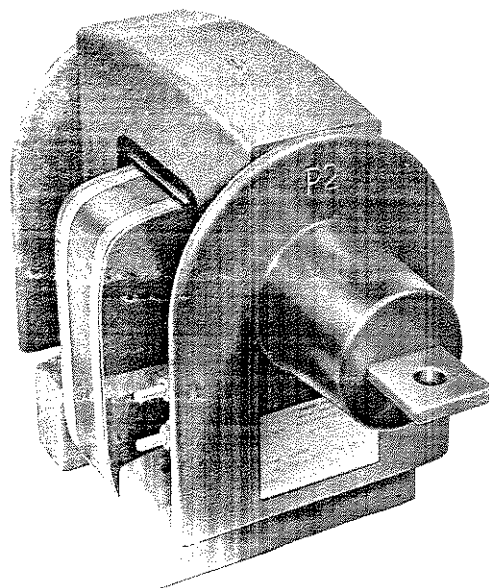


Figure 5.24 Slip-over type current transformer.

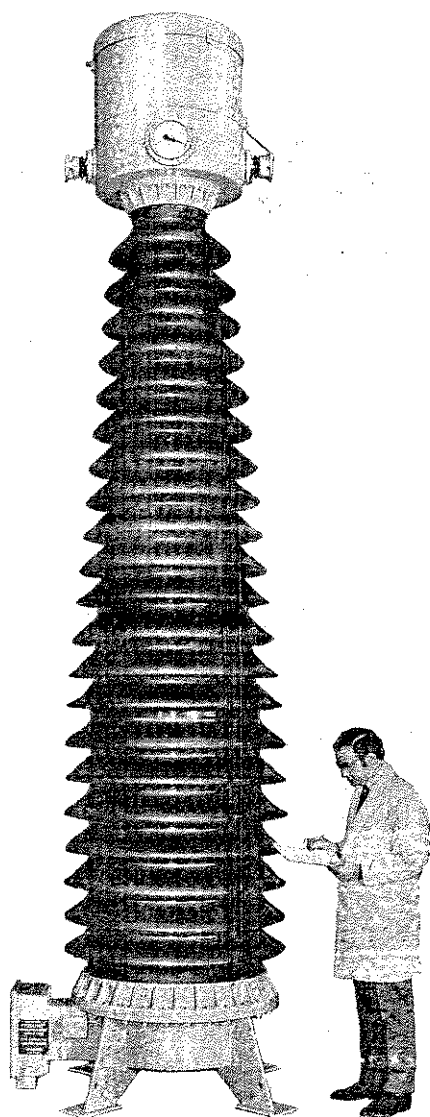


Figure 5.25 525kV 2000A outdoor oil-insulated current transformer of hair-pin primary construction type.

within the core saturation limits. Errors in current transformation are thereby significantly reduced when compared with those with the gapless type of core.

#### Linear current transformers

The 'linear' current transformer constitutes an even more radical departure from the normal solid core CT in that it incorporates an appreciable air gap, for example 7.5–10mm. As its name implies the magnetic behaviour tends to linearization by the inclusion of this gap in the magnetic circuit. However, the purpose of introducing more reluctance into the magnetic circuit is to reduce the value of magnetizing reactance, this in turn reduces the secondary time-constant of the CT thereby reducing the overdimensioning factor necessary for faithful transformation.

#### Separately mounted current transformers

Where bushings are not available to mount EHV current transformers, these can be provided as free-standing units. Here, the primary conductor is bent into an elongated U-form and is contained within an oil-filled porcelain insulator. The secondary winding and core are mounted on

the lower part of the U. Usually several cores and secondary windings for separate functions are provided on the one primary conductor.

In an alternative design, the insulation is provided entirely over the secondary windings. The primary conductor is a straight bar which is not insulated from the enclosing metal tank at one end and only lightly so at the other. The tank is mounted on a hollow porcelain insulator which provides insulation to system voltage; the secondary leads from the current transformers are brought down the centre of the supporting insulator. The highly insulated cores and windings are surrounded by an insulating medium such as oil or sulphur hexafluoride gas,  $\text{SF}_6$ , this being a gas with an unusually high dielectric strength.

As in the alternative arrangement, several separate cores and windings can be provided.

Figures 5.22 to 5.28 show a selection of current transformers for high voltage systems.

#### 5.3.7

##### Secondary winding impedance

As a protection CT may be required to deliver high values of secondary current, the secondary winding resistance must be made as low as practicable.

Secondary leakage reactance also occurs, particularly in wound primary current transformers, although its precise measurement is difficult. The non-linear nature of the CT magnetic circuit makes it difficult to assess the definite ohmic value representing secondary leakage reactance.

It is however normally accepted that a current transformer is of the low reactance type provided that, in the spirit of, if not in the exact words of BS 3938 (Section 4.4), the following conditions prevail:

- The core is of the jointless ring type (including spirally wound cores).
- The secondary turns are substantially evenly distributed along the whole length of the magnetic circuit, except that a circumferential spacing which does not exceed 2cm on the outer periphery, or which subtends an angle between radii not exceeding  $30^\circ$ , whichever is the greater, is permissible between the two ends of the winding.
- The primary conductor(s) passes through the approximate centre of the core aperture or, if wound, is approximately evenly distributed along the whole length of the magnetic circuit.
- Flux equalizing windings, where fitted to the requirements of the design, consist of at least four parallel connected coils, evenly distributed along the whole length of the magnetic circuit, each coil occupying one quadrant. Such an arrangement ensures substantially even flux distribution within the core irrespective of the effect of the magnetic field of the return conductor in situations where the latter is in close proximity.

Alternatively, when a current transformer does not obviously comply with all of the above requirements it may be proved to be of low-reactance where:

- The composite error, as measured in the accepted way, does not exceed by a factor of 1.3 that error obtained directly from the  $V$ - $I$  excitation characteristic of the secondary winding.

#### 5.3.8

##### Secondary current rating

The burden at rated current imposed by most relays or instruments is largely independent of the rated value of current. This is because the winding of the device has to develop a given number of ampere-turns at rated current, so that the actual number of turns is inversely proportional to the current, and the impedance of the winding varies inversely with the square of the current rating.



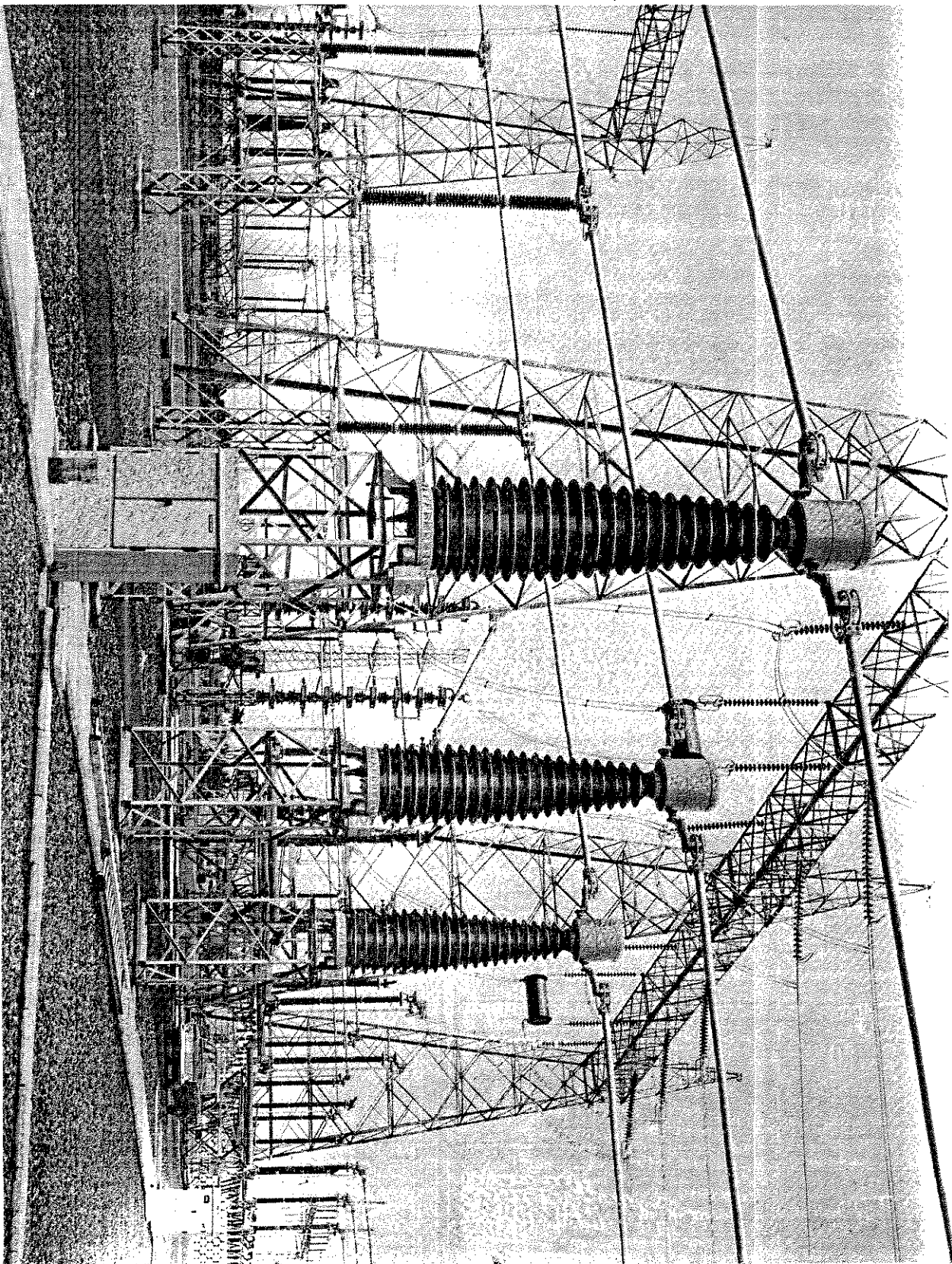


Figure 5.26 Three-phase bank of 525kV 2000A outdoor oil-insulated current transformers of hair-pin primary construction type.

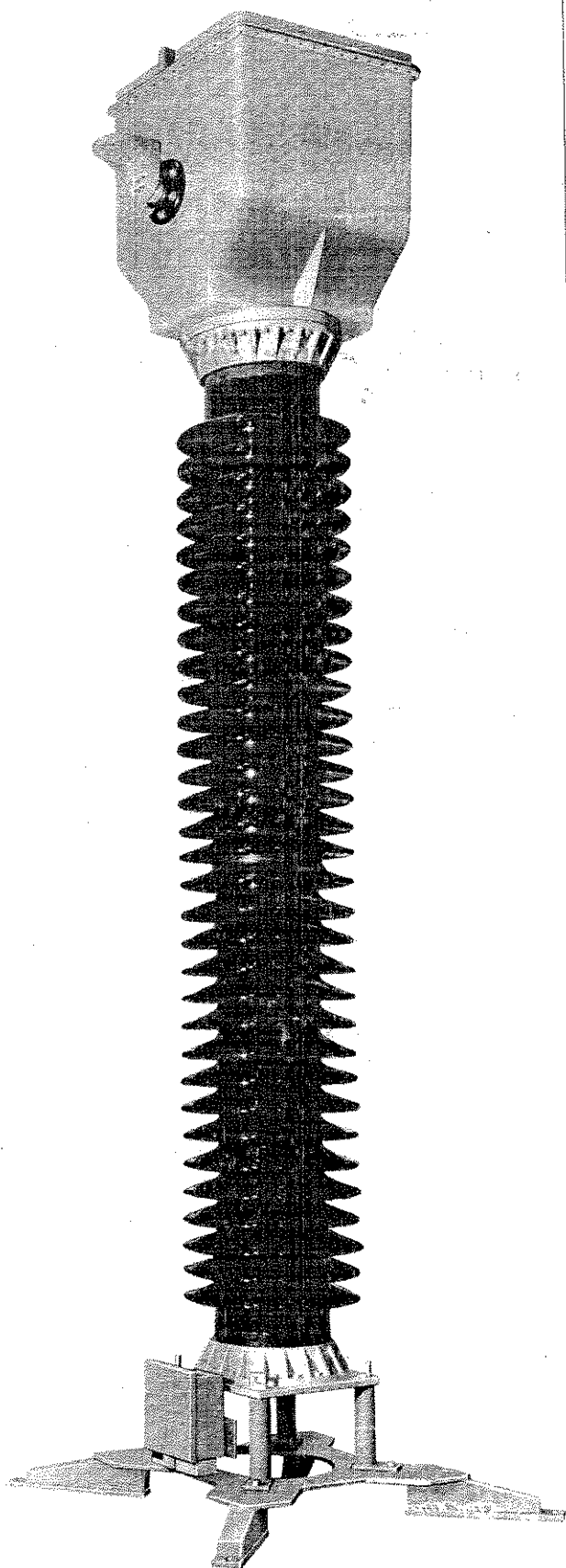


Figure 5.27 420kV live tank oil-insulated current transformer.

Interconnecting leads, however, are not so varied, being commonly of standard cross-section regardless of rating. Where the leads are long, their resistance may be appreciable, and the resultant burden will vary with the square of the current rating. For example a lead run of the order of 200 metres, a typical distance for outdoor EHV switchgear, could have a 'loop' resistance of approximately 3 ohms.

For many years a rated secondary current of 5A has been regarded as standard.

If such a CT is used with the leads discussed above, the lead burden alone would be 75VA, to which must be added the useful burden of perhaps 10VA, making a total of 85VA. Such a burden would require the CT to be very large and expensive, particularly if a large accuracy limit factor were also applicable.

On the other hand, if the CT secondary rating is 1A, the lead burden is reduced to 3VA, so that with the same relay burden the total becomes 13VA, which could be provided by a CT of normal dimensions.

It will be noted that for normal circumstances there is little to be gained by further reducing the current rating. Moreover, where the primary rating is high, say above 2000A, a CT of higher secondary rating would be used, to limit the number of secondary turns. In such a situation secondary ratings of 2A, 5A or, in extreme cases, 20A, might be used. Here, an auxiliary CT located near to the main unit may be needed, to step down to a low current rating.

### 5.3.9

#### Open-circuit secondary voltage

It was noted in Section 5.3 that the secondary circuit must not be broken with primary current flowing.

With the secondary circuit open, there is no secondary m.m.f. to oppose that due to the primary current, and all the primary m.m.f. acts on the core as a magnetizing quantity. If the current is appreciable, the core is driven into saturation on each half wave and the high rate of change of flux while the primary current passes through zero induces a high peak e.m.f. in the secondary winding. With rated primary current flowing, this e.m.f. may be a few hundred volts for a small CT but may be many kilovolts for a large high ratio protective CT. With system fault current flowing, the voltage would be raised in nearly direct proportion to the current value.

Such voltages are dangerous not only to the insulation of the CT and connected apparatus, but more important, to life itself. The condition must therefore be avoided, and if the secondary circuit has to be disconnected while primary current is flowing it is essential first to short-circuit the secondary terminals of the CT. The conductor used for this purpose must be securely connected and of adequate rating to carry the secondary current, including what would flow if a primary system fault should occur.

### 5.3.10

#### Rated short-time current

As with other parts of the power system, a current transformer is overloaded while system short-circuit currents are flowing and will be short-time rated.

The rated short-time current is defined as the r.m.s. value of the a.c. component of the current which a current transformer is capable of carrying for the rated time without being damaged by thermal or dynamic effects, the peak value of the first cycle of current being not less than 2.55 times the r.m.s. value of the symmetrical current.

From the thermal aspect, the short-time current is necessarily associated with a time, which may be 0.25, 0.5, 1.0, 2.0 or 3.0 seconds.

The maximum dynamic effects, on the other hand, are experienced during the first cycle, forces being proportional to the square of the instantaneous values of current,



and hence being more than three times greater at the peak of the first major asymmetrical loop than subsequently with the symmetrical current.

It follows that if a CT is assigned a given value of short-time current and time, the unit will carry a lower current for a longer time in inverse proportion to the square of the ratio of current values. The converse, however, cannot be assumed, and larger current values than the S.T.C. rating are

not permissible for any duration unless justified by a new rating test to prove the dynamic capability.

### 5.3.11

#### Transient response of a current transformer

The normal theory of the current transformer is based on an input current having a steadily alternating waveform which

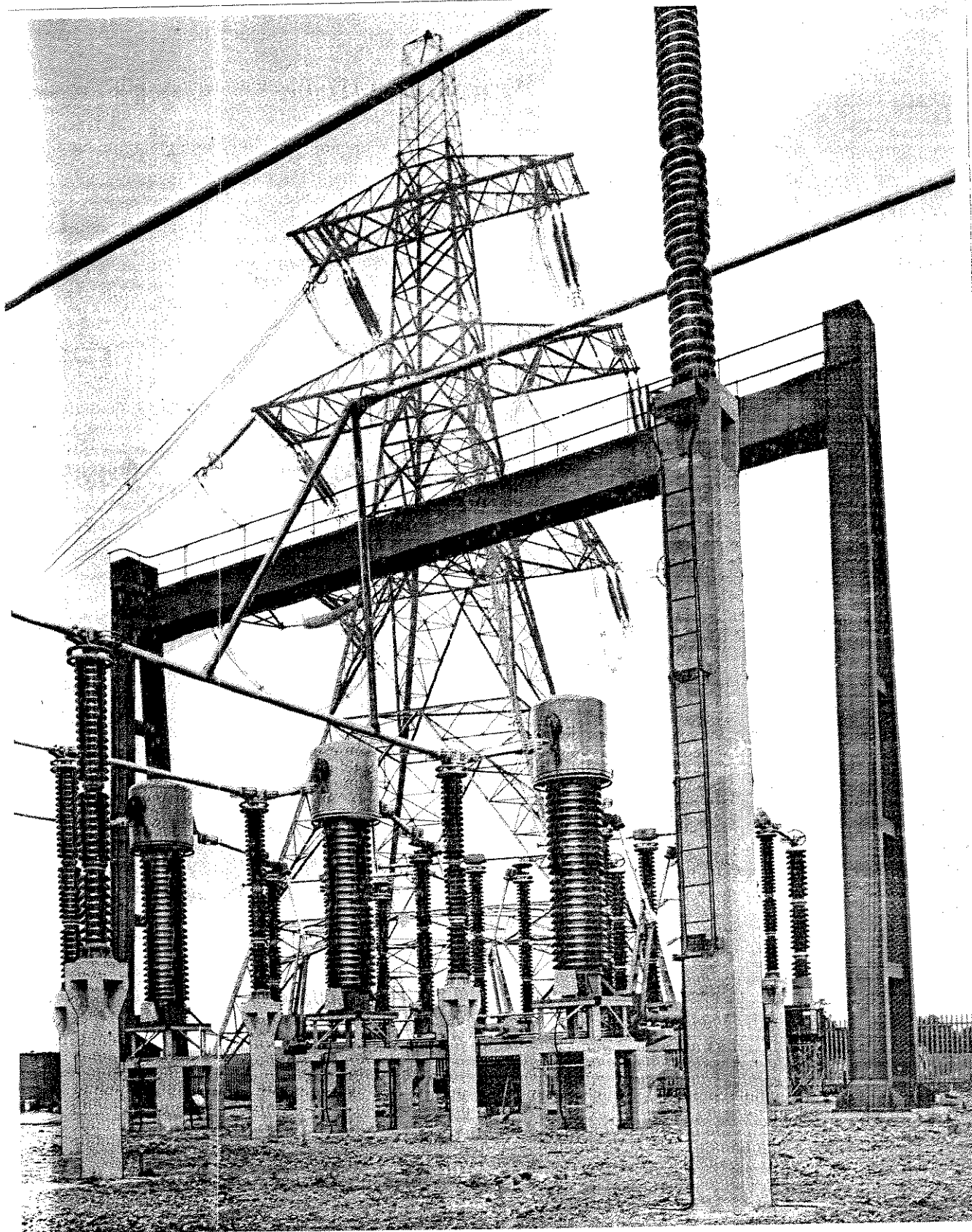


Figure 5.28 Three-phase bank of 400kV live tank gas ( $\text{SF}_6$ ) insulated current transformers

in general is substantially sinusoidal. Under these conditions the response can be interpreted in terms of vectors as in Section 5.3.1. This treatment is satisfactory in all applications for measurement and low-speed relay operation. When accuracy of response during very short intervals is being studied, it is necessary to examine what happens when the primary current is suddenly changed. The effects are most important, and were first observed in connection with balanced forms of protection, which were liable to operate unnecessarily when short-circuit currents were suddenly established.

### 5.3.12

#### Primary current transient

The power system, neglecting load circuits, is mostly inductive, so that when a short circuit occurs, the fault current which flows is given by:

$$i_p = \frac{E_p}{\sqrt{R^2 + \omega^2 L^2}} [\sin(\omega t + \beta - \alpha) + \sin(\alpha - \beta) e^{-(R/L)t}] \quad \dots \text{Equation 5.1}$$

where  $E_p$  = peak system e.m.f.  
 $R$  = system resistance  
 $L$  = system inductance  
 $\beta$  = initial phase angle governed by instant of fault occurrence  
 $\alpha$  = system power factor angle  
 $= \tan^{-1} \omega L/R$

The first term of Equation 5.1 represents the steady state alternating current, while the second is a transient quantity responsible for displacing the wave-form asymmetrically.

$\frac{E_p}{\sqrt{R^2 + \omega^2 L^2}}$  is the steady state peak current  $I_p$ .

Also, the maximum transient occurs when  $\sin(\alpha - \beta) = \text{unity}$ ; no other condition need be examined.  
 So:

$$i_p = I_p \left[ \sin\left(\omega t - \frac{\pi}{2}\right) + e^{-(R/L)t} \right] \quad \dots \text{Equation 5.2}$$

When the current is passed through the primary winding of a current transformer, the response can be examined by replacing the CT with an equivalent circuit as shown in Figure 5.18(b).

As the 'ideal' CT has no losses, it will transfer the entire function, and all further analysis can be carried out in terms of equivalent secondary quantities ( $i_s$  and  $I_s$ ). A simplified solution is obtainable by neglecting the exciting current of the CT, that is, by assuming the CT to have infinite inductance.

The flux developed in an inductance is obtained by integrating the applied e.m.f. through a time interval.

$$\phi = K \int_{t_1}^{t_2} v \, dt \quad \dots \text{Equation 5.3}$$

For the CT equivalent circuit, the voltage is the drop on the burden resistance  $R_b$ .

Integrating for each component in turn:

The steady state peak flux is given by:

$$\phi_A = KR_b I_s \int_{\pi/\omega}^{3\pi/2\omega} \sin\left(\omega t - \frac{\pi}{2}\right) dt = \frac{KR_b I_s}{\omega} \quad \dots \text{Equation 5.4}$$

The transient flux is given by:

$$\phi_B = KR_b I_s \int_0^{\infty} e^{-(R/L)t} dt = \frac{KR_b I_s L}{R} \quad \dots \text{Equation 5.5}$$

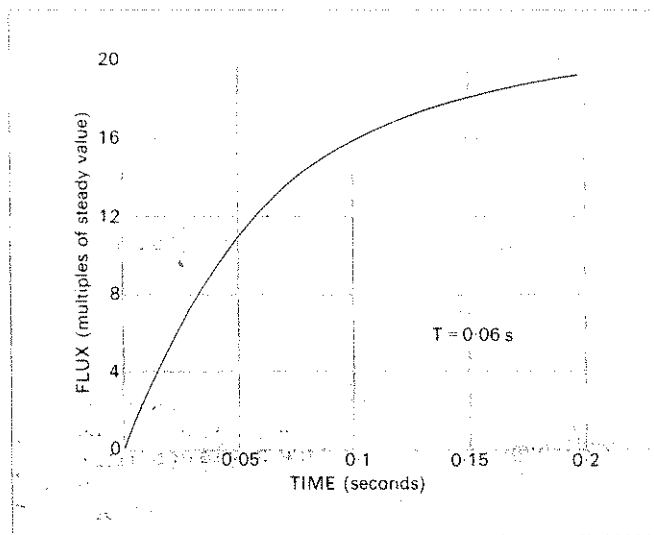


Figure 5.29 Response of a CT of infinite shunt impedance to transient asymmetric primary current.

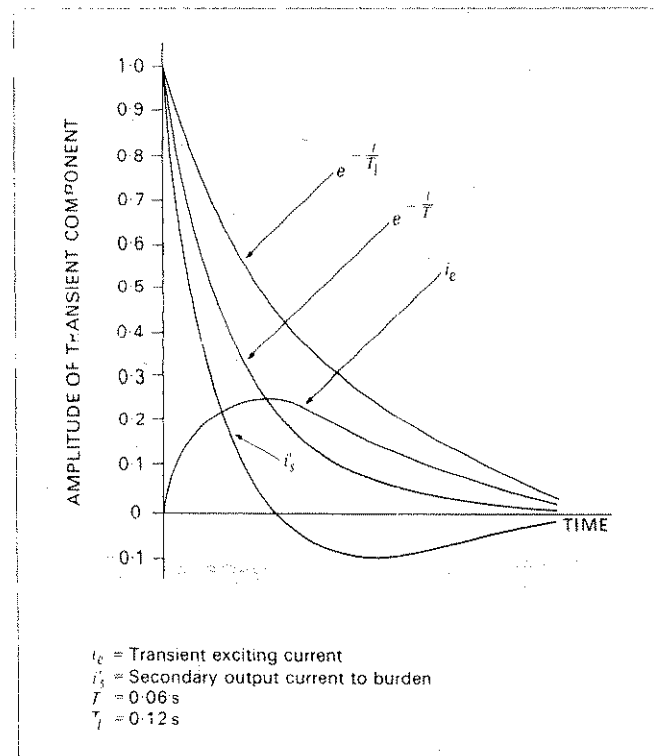


Figure 5.20 Response of a current transformer to a transient asymmetric current.

Hence, the ratio of the transient flux to the steady state value is:

$$\frac{\phi_B}{\phi_A} = \frac{\omega L}{R} = \frac{X}{R}$$

where  $X$  and  $R$  are the primary system reactance and resistance values.

The CT core has to carry both fluxes, so that:

$$\phi_C = \phi_A + \phi_B = \phi_A \left(1 + \frac{X}{R}\right) \quad \dots \text{Equation 5.6}$$

The term  $(1 + X/R)$  has been called the 'transient factor', the core flux being increased by this factor during the transient asymmetric current period.

From this it can be seen that the ratio of reactance to resistance of the power system is an important feature in the study of protective gear behaviour.

Alternatively,  $L/R$  is the primary system time constant  $T$ , so that the transient factor can be written:

$$T.F. = 1 + \frac{\omega L}{R} = 1 + \omega T$$

Again,  $fT$  is the time constant expressed in cycles of the a.c. quantity  $T'$ , so that:

$$T.F. = 1 + 2\pi fT = 1 + 2\pi T'$$

This latter expression is particularly useful when assessing an oscillogram of a fault current, because the time constant in cycles can be easily estimated, and leads directly to the transient factor. For example, a system time constant of three cycles results in a transient factor of  $(1 + 6\pi)$ , or 19.85; that is, the CT would be required to handle almost twenty times the maximum flux produced under steady state conditions. The above theory is sufficient to give a general view of the problem. In this simplified treatment, no reverse voltage is applied to demagnetize the CT, so that the flux would build up as shown in Figure 5.29.

Since a CT requires a finite exciting current to maintain a flux, it will not remain magnetized (neglecting hysteresis), and for this reason a complete representation of the effects can only be obtained by including the finite inductance of the CT in the calculation. The response of a current transformer to a transient asymmetric current is shown in Figure 5.30.

Let

$i_c$  = the nominal secondary current

$i$  = the actual secondary output current

$i_e$  = the exciting current

then

$$i = i_c + i_e \quad \dots \text{Equation 5.7}$$

also

$$L \frac{di_e}{dt} = R_b i_e \quad \dots \text{Equation 5.8}$$

whence

$$\frac{di_e}{dt} + \frac{R_b i_e}{L} = \frac{R_b i_c}{L} \quad \dots \text{Equation 5.9}$$

which gives for the transient term

$$i_e = I_1 \frac{T}{T_1 - T} (e^{-t/T_1} - e^{-t/T})$$

where  $T$  = primary system time constant  $L/R$

$T_1$  = CT secondary circuit time constant  $L_c/R_b$

$I_1$  = prospective peak secondary current

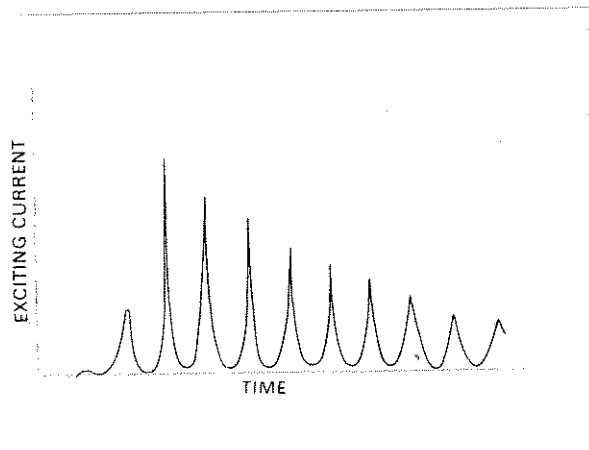


Figure 5.31 Typical exciting current of CT during transient asymmetric input current.

### 5.3.13

#### Practical conditions

The foregoing theory deviates from practice for the following reasons:

a. No account has been taken of secondary leakage or burden inductance. This is usually small compared with  $L_c$ , so that it has little effect on the maximum transient flux.

b. Iron loss has not been considered. This has the effect of reducing the secondary time constant, but the value of the equivalent resistance is variable, depending upon both the sine and exponential terms. Consequently, it cannot be included in any linear theory and is too complicated for a satisfactory treatment to be evolved.

c. The theory is based upon a linear excitation characteristic. This is only approximately true up to the knee-point of the excitation curve and is not at all true beyond this point. A precise solution allowing for non-linearity is not practicable; solutions have been sought by replacing the excitation curve with a number of chords; a linear analysis can then be made for the extent of each chord.

The above theory is sufficient, however, to give a good insight into the problem and to allow most practical issues to be decided.

d. The effect of hysteresis, apart from loss as discussed under (b) above, is not included. Hysteresis makes the inductance different for flux build up and decay, so that the secondary time constant is variable. Moreover, the ability of the core to retain a 'remanent' flux means that the value of  $\phi_B$  developed in Equation 5.5 has to be regarded as an increment of flux from any possible remanent value positive or negative. The formula would then be reasonable provided the applied current transient did not produce saturation.

It will be seen that a precise calculation of the flux and excitation current is not feasible; the value of the study is to explain the observed phenomena. The asymmetric (or d.c.) component can be regarded as building up the mean flux over a period corresponding to several cycles of the sinusoidal component, during which period the latter component produces a flux swing about the varying 'mean level' established by the former. The asymmetric flux ceases to increase when the exciting current is equal to the total asymmetric input current, since beyond this point the output current, and hence the voltage drop across the burden resistance, is negative.

Saturation makes the point of equality between the excitation current and the input occur at a flux level lower than would be expected from linear theory.

When the exponential component drives the CT into saturation, the magnetizing inductance decreases, causing a large increase in the alternating component  $i_e$ .

The total exciting current during the transient period is of the form shown in Figure 5.31 and the corresponding resultant distortion in the secondary current output, due to saturation, is shown in Figure 5.32.

The presence of residual flux varies the starting point of the transient flux excursion on the excitation characteristic. Remanence of like polarity to the transient will reduce the value of asymmetric current of given time constant which the CT can transform without severe saturation; conversely, reverse remanence will greatly increase the ability of a CT to transform transient current.

If the CT were the linear non-saturable device considered in the analysis, the sine current would be transformed without loss of accuracy. In practice the variation in excitation inductance caused by transferring the centre of the flux swing to other points on the excitation curve causes an error which may be very large. The effect on measurement is of little consequence, but for protective gear which is required to function during fault conditions, the effect is more serious. The output current is reduced during

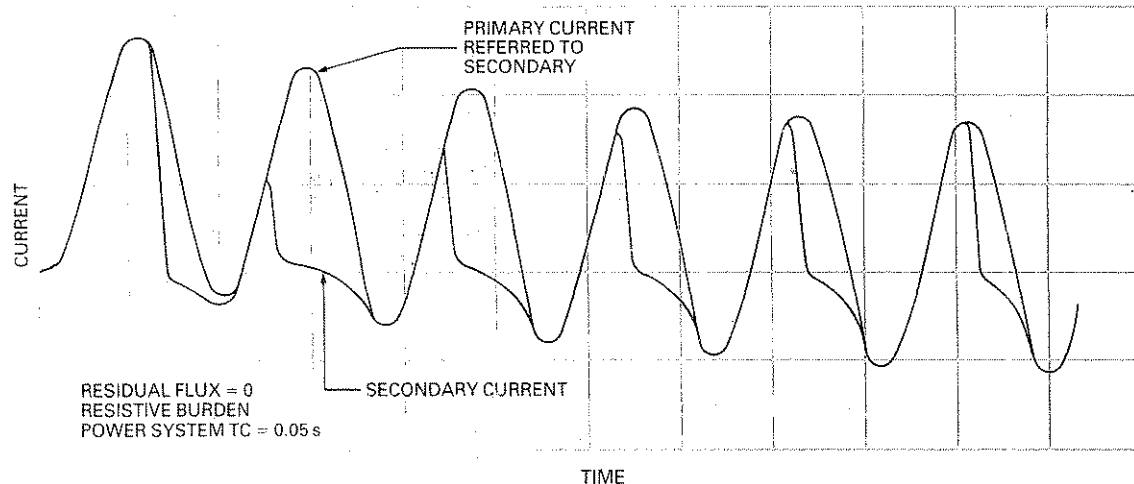


Figure 5.32 Distortion in secondary current due to saturation.

transient saturation, which may prevent the relays from operating if the conditions are near to setting. This must not be confused with the increased r.m.s. value of the primary current due to the asymmetric transient, a feature which sometimes offsets the increased ratio error. In the case of balanced protection, during through faults the errors of the several current transformers may differ and produce an out-of-balance quantity, causing unwanted operation.

#### 5.3.14

##### Harmonics during the transient period

When a CT is required to develop a high secondary e.m.f. under steady state conditions, the non-linearity of the excitation impedance causes some distortion of the output waveform; such a waveform will contain, in addition to the fundamental current, odd harmonics only.

When, however, the CT is saturated uni-directionally while being simultaneously subjected to a small a.c. quantity, as in the transient condition discussed above, the output will contain all orders of harmonics, odd and even.

Usually the lower numbered harmonics are of greatest amplitude and the second and third harmonic components may be of considerable value. This matter is of importance with certain protective systems which have special harmonic sensitivity.

#### 5.3.15

##### Test windings

On-site conjunctive testing of current transformers and the apparatus which they energize is often required. It may be difficult, however, to pass a suitable value of current through the primary windings, because of the scale of such current and in many cases because access to the primary conductors is difficult. Additional windings may be provided to make such tests easier, these windings usually being rated at 10A; that is, 10A passed through the test winding should produce the same output as would the rated primary current passed through the primary winding.

The test winding will inevitably occupy appreciable space and will therefore increase the dimensions and cost of the CT or alternatively, for given dimensions, will reduce the normal performance of the current transformer. This fact should be weighed against the convenience achieved; very often it will be found that the tests in question can be replaced by alternative procedures.

When energizing a test winding the normal primary winding should be open-circuited; if it is not, the CT will summate the effects of primary and test current. Conversely, in normal operation the test winding should be left open-circuited.

# Electromechanical relays

- 6.1 Introduction.
- 6.2 Basic types of relay.
- 6.3 Type of measurement.
- 6.4 Comparators.
- 6.5 Bias.
- 6.6 Principal types of relay.
- 6.7 Moving coil relays.
- 6.8 Induction pattern relays.
- 6.9 Thermal relays.
- 6.10 Miscellaneous relays.
- 6.11 Contact behaviour.
- 6.12 Coil rating.
- 6.13 A.C. coil connections.
- 6.14 Mechanical stability.
- 6.15 Maintenance.

## 6.1

### Introduction

The fundamental power system quantities of current and voltage, transmitted through measuring transformers where necessary, are measured and interpreted by relays either singly or in combination, in order to provide protection. Electrical relays are of many and varied types; although these have something in common, it is difficult to give a precise definition of a relay which covers all types without also including a large number of other devices. The following definition may be helpful.

An electrical relay is a device designed to produce sudden, predetermined changes in one or more electrical output circuits, when certain conditions are fulfilled in the electrical input circuits controlling the device.

A protective relay is an electrical relay designed to initiate disconnection of a part of an electrical installation, and/or to operate a warning signal, in the case of a fault or other abnormal condition in the installation, and with the minimum interruption to service.

## 6.2

### Principles of the relay

A relay can be designed to respond to any observable effect; so many forms have been produced that a detailed description of each would be impracticable.

Relay elements can be classified under the following broad headings.

- a. Attracted armature
- b. Moving coil
- c. Induction
- d. Thermal
- e. Motor-operated
- f. Mechanical
- g. Magnetic amplifier
- h. Thermionic
- i. Semiconductor
- j. Photo-electric

Of these main groups, types (g)–(j) are commonly known as 'static' relays and are dealt with in Chapter 7. Types (a)–(f) are described below.

## 6.3

Discriminative protection involves an analysis of the power

system quantities (voltage and current) which are present at the relaying points and their interpretation in terms of composite functions such as impedance and power. This analysis is performed by the protective relays, the operation of which can be classified according to the type of measurement which is made.

### 6.3.1 Magnitude

All relays that respond to current or voltage magnitude and have settings in such terms are included in this class. Other relays, which are energized by voltage but are calibrated in terms of some other fundamental quantity such as frequency, for example, can also be included in this category. Relays that have a current setting, but which by the interconnection of current transformers make a more complex measurement, are best assessed in terms of the performance of the composite protective system.

Relays can be fitted with multiple windings; when these are energized simultaneously, the relay will respond according to the sum (or difference) of the input quantities.

### 6.3.2 Product measurement

The induction relay operates by means of the interaction of two alternating fluxes which are separately produced and which retain their identities. The operating force or torque so produced is proportional to each of the fluxes and hence also to their product. The effective torque is given by:

$$T = K\Phi_1\Phi_2 \sin \alpha \quad \dots \text{Equation 6.1}$$

where  $T$  = torque

$\Phi_1, \Phi_2$  = interacting fluxes

$\alpha$  = phase angle between  $\Phi_1$  and  $\Phi_2$ .

The relay can be arranged to respond to any quantity which is equal to the product of two alternating components. Such response is typically a measurement of power but can also be related to the product of any two vectors of the same frequency. If quantities of different frequencies are applied, the average torque will be zero, although if the frequencies are very close in value, a beat frequency operation will occur.

### 6.3.3 Ratio measurement

It is not practicable to make a relay that develops a torque equal to the quotient of two a.c. quantities. This, however, is not important; the only significant condition for a relay is its setting and the setting can be made to correspond to a ratio regardless of the component values over a wide range.

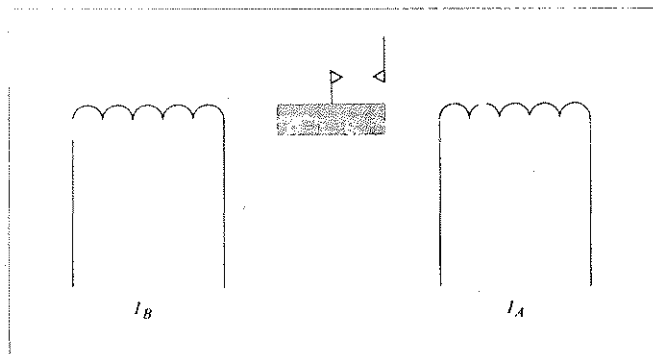


Figure 6.1 Principle of ratio measurement.

Figure 6.1 shows symbolically a relay movement having two windings exerting opposed forces on a single armature. If the individual forces are proportional to the exciting currents, then:

$$F_A = K_1 I_A$$

$$F_B = K_2 I_B$$

and when a state of balance is achieved:

$$K_1 I_A = K_2 I_B$$

$$\frac{I_A}{I_B} = \frac{K_2}{K_1} = C \quad \dots \text{Equation 6.2}$$

If the element is sensitive, a very small departure from the balance condition will cause operation, so that setting and balance are nearly synonymous. For this reason the relay will operate when the ratio is exceeded, regardless of the separate values of  $I_A$  and  $I_B$ . Naturally, this will not hold true for an unlimited range of  $I_A$  and  $I_B$ .

This principle has been very extensively used in the design of impedance relays, and in relays having a proportionate biasing feature.

Relays for ratio measurement have been constructed as attracted armature, moving coil, and induction type elements, and as bridge networks of rectifier elements.

## 6.4 COMPARATORS

It has been seen above that relays may measure different functions of applied quantities and that more specialized relays are concerned with making a comparison between two or more different inputs. A number of different types of comparator exists, and it is worth examining the properties and interrelations of these different types in order to understand the specialized devices in which they are used.

### 6.4.1 Amplitude comparator

Such a comparator will operate when the magnitude of one applied signal exceeds that of another and resets when the converse is true. A typical device could be of the attracted armature balanced beam type or the double wound moving-coil type, as shown in Figure 6.2. If such a device is supplied with composite signals derived from the system current and voltage so that one winding receives  $K_1 V + K_2 I$  and the other receives  $K_1 V - K_2 I$ , the resulting response will be directional. This is obvious enough from simple in-phase quantities, but it will be found on investigation that it is also true if  $V$  and  $I$  have a phase displacement, the resultant unbalanced force then being proportional to the cosine of the angular displacement. So for mixed input signals an amplitude comparator gives a product-type response.

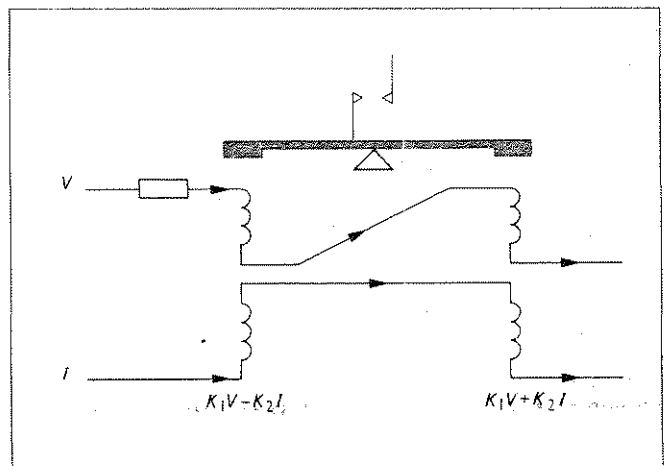


Figure 6.2 Directional relay using amplitude comparator

### 6.4.2 Product type comparators

The induction element is a typical example of a product-

type device. If such a device is fed with mixed signals, as in the above example, the resulting torque will be proportional to  $(K_1V + K_2I) \times (K_1V - K_2I)$ . This product will always be positive provided  $K_1V > K_2I$ . When the converse is true the product becomes negative, and the resulting torque in the movement is reversed. So in this case a product comparator gives an amplitude response.

One successful and well proven comparator has been based on rectifier bridge networks.

### 6.4.3

#### Rectifier bridge amplitude comparator

This comparator consists of two full-wave bridge rectifiers with d.c. output terminals interconnected positive to negative in a circulating fashion. A sensitive polarized detecting relay is connected across the interconnecting leads, as in Figure 6.3.

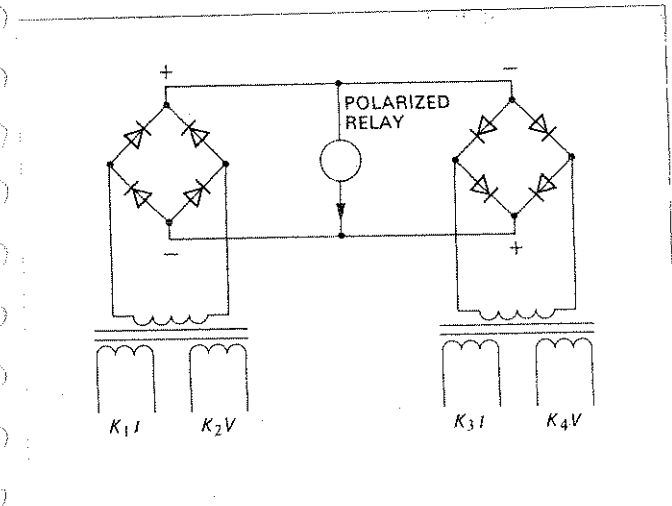


Figure 6.3 Rectifier bridge amplitude comparator.

When such an arrangement receives equal a.c. input signals at each rectifier bridge the resulting output currents circulate round the interconnecting leads without energizing the detecting element. If, however, one input is increased above the value of the other the difference current will flow in the relay. If the second signal is increased to be the larger the difference current flowing in the relay element becomes reversed; in this way the polarized relay can make a very sensitive comparison of the magnitudes of the two signals.

The input signals can be of composite form, as described above; this leads to a wide range of operation characteristics.

### 6.4.4

#### Generalized amplitude comparator

Mixed signals derived from current and voltage sources are fed to the two sides of a comparator which will balance when the moduli of these signals are equal. So:

$$|K_1I + K_2V| = |K_3I + K_4V|$$

dividing by  $I$  and substituting with  $V/I = Z = (R + jX)$ :

$$|K_1 + K_2(R + jX)| = |K_3 + K_4(R + jX)|$$

$$|(K_1 + K_2R) + jK_2X| = |(K_3 + K_4R) + jK_4X|$$

$$(K_1 + K_2R)^2 + K_2^2X^2 = (K_3 + K_4R)^2 + K_4^2X^2$$

$$K_1^2 + K_2^2R^2 + 2K_1K_2R - K_3^2 - K_4^2R^2 - 2K_3K_4R + K_2^2X^2 - K_4^2X^2 = 0$$

$$(K_2^2 - K_4^2)R^2 + (K_2^2 - K_4^2)X^2 + 2(K_1K_2 - K_3K_4)R + (K_1^2 - K_3^2) = 0$$

... Equation 6.3

Comparing this with the general equation for the circle:

$$x^2 + y^2 + 2gx + 2hy + c = 0$$

where

$$x = R \quad y = X$$

$$g = \frac{K_1K_2 - K_3K_4}{(K_2^2 - K_4^2)}$$

$$h = 0$$

$$c = \frac{(K_1^2 - K_3^2)}{(K_2^2 - K_4^2)}$$

So the characteristic is a circle on the  $R$ - $X$  plane with centre

$$(-g, -h) = \left( \frac{K_3K_4 - K_1K_2}{K_2^2 - K_4^2}, 0 \right)$$

and radius

$$(g^2 + h^2 - c)^{1/2} = \frac{K_1K_4 - K_2K_3}{K_2^2 - K_4^2}$$

If  $K_1 = K_3$ ,  $-g =$  radius, circle passes through origin.

If  $K_1 \neq K_3$  the circle is offset.

If  $K_1 = K_3$  and  $K_2 = -K_4$ :

$$\begin{aligned} -g &= \frac{K_3K_4 - K_1K_2}{K_2^2 - K_4^2} \\ &= \frac{K_1(K_4 - K_2)}{(K_2 + K_4)(K_2 - K_4)} \\ &= \frac{-K_1}{(K_2 + K_4)} = \frac{-K_1}{0} = \infty \end{aligned}$$

$$\begin{aligned} \text{Radius} &= \frac{K_1K_4 - K_2K_3}{K_2^2 - K_4^2} \\ &= \frac{K_1(K_4 - K_2)}{(K_2 + K_4)(K_2 - K_4)} \\ &= \infty. \end{aligned}$$

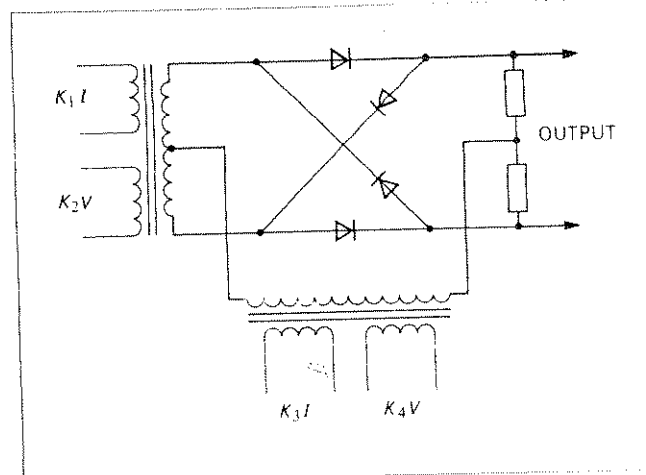


Figure 6.4 Rectifier bridge phase comparator.

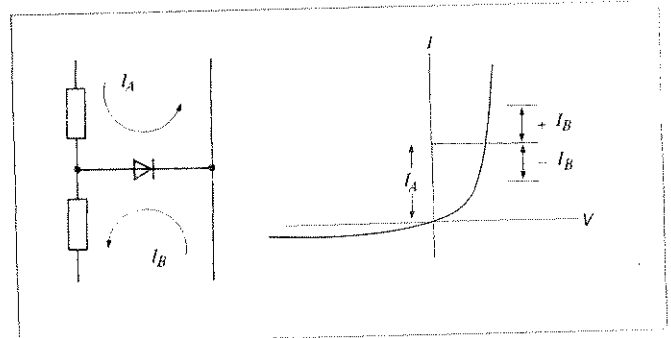


Figure 6.5 Current/voltage characteristic of diode.

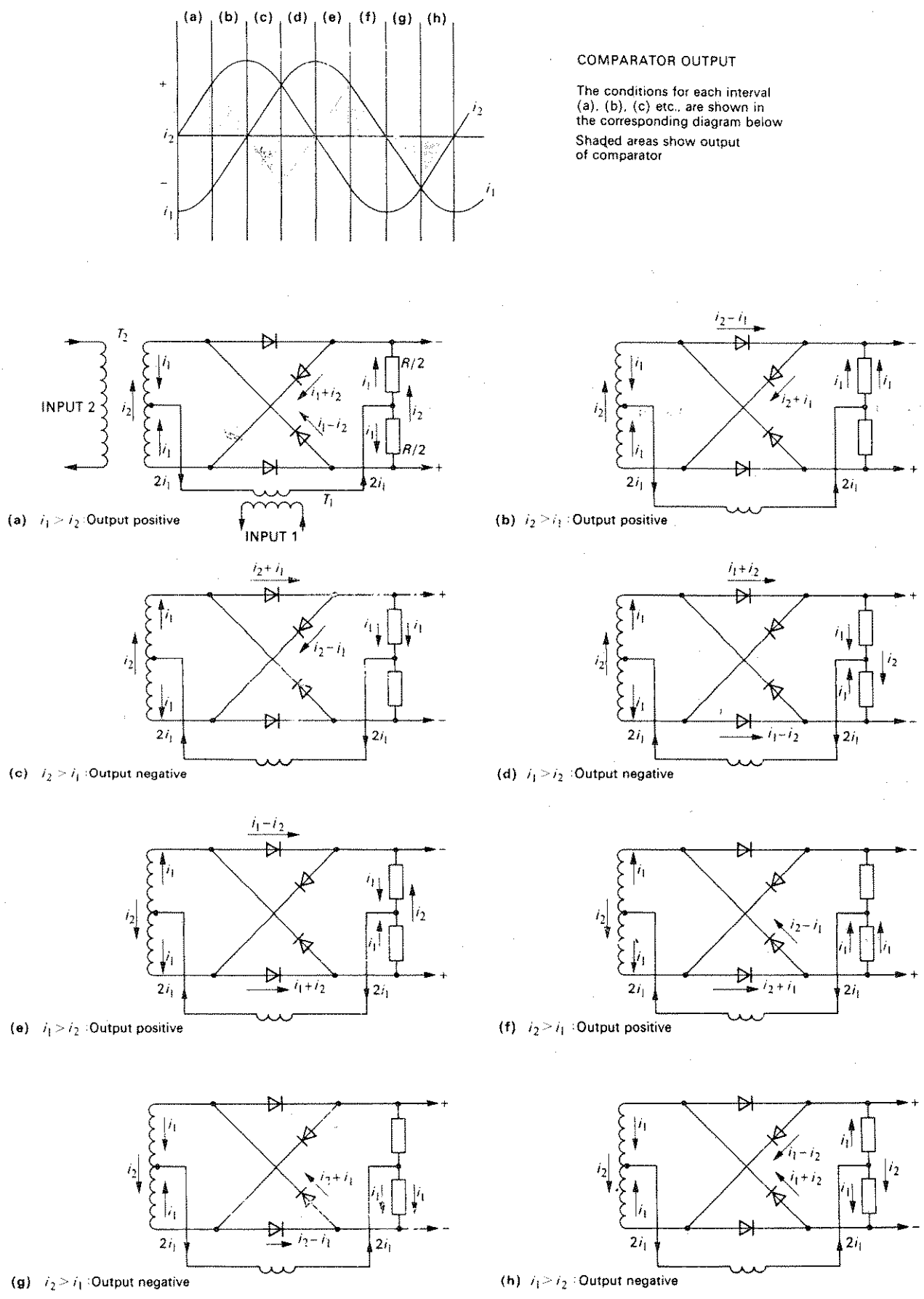


Figure 6.6 Current flow in and output from phase comparator, fault at boundary.



So the characteristic is a straight line passing through the origin, that is, a directional characteristic.

It is possible to follow this subject further using more complex input signals and deriving resulting characteristics which have elliptical or other forms.

#### 6.4.5 Rectifier bridge phase comparator

A bridge circuit as shown in Figure 6.4 responds to the relative phase of two input signals. In order to understand this circuit it is important to realize that a rectifier cell operates because of a large change in resistance that occurs in the region of zero current, the operating characteristics being of the form shown in Figure 6.5.

When the diode is biased away from the origin by one current  $I_A$ , a second smaller current  $I_B$  from another source can flow through the diode junction in either direction, encountering only the small dynamic resistance of the diode at the biasing point. So signal  $I_A$  can be said to open the diode 'gate'. Similarly, a reverse bias will close the gate for any smaller value signal.

With this in mind the action of the bridge of Figure 6.4 can be studied. Figure 6.6(a) shows two input signals and the condition of the bridge at successive points in the cycle is shown in Figure 6.6, (b)–(h). It will be seen that the polarity of the output is dependent only on the relative polarity of the two input signals, the magnitude of the output being proportional to the weaker of the two inputs at any instant. The output signal is of the form shown in Figure 6.6, if the positive and negative loops of bridge output are equal for quadrature input conditions, but for other phase angles the output loops of one polarity are increased and those of opposite polarity diminished until for in-phase input signals the output is entirely uni-directional. If, therefore, the output is applied to a smoothing circuit (or polarized relay) which integrates the bridge output, the resulting signal (or operation) will correspond to the relative phase of the bridge input signals. The response which is finally obtained will depend upon the source of the inputs but the locus of marginal operation plotted on an Argand diagram can have a circular or linear form.

Phase comparison bridges using transistors instead of diodes can be arranged to accept more than two inputs with a resulting output of complex form corresponding to a number of basic overlapping curves.

The use of these devices has now reached a stage where virtually any shape of characteristic can be produced if required. Design therefore consists very largely of visualizing the form of response which would be most beneficial in a given application, knowing that the characteristic when chosen can probably be realized. Departure from the fundamental characteristics of straight line or circle for more complex forms inevitably involves the design of more complicated and expensive equipment. The pursuit of the ideal device must not be taken too far, as perfection in the design of a characteristic may well cost much more than can be justified by the gain in performance. A balance must be sought between performance and cost.

#### 6.5

##### BIAS

Certain protection systems are confined in response to faults within a clearly defined zone; this performance is achieved by making a critical comparison of currents at zone boundaries. All through currents flowing to faults or loads external to the zone should balance in the comparator, giving a zero output to the sensing device. Errors, however, arise in the current transformers and other component parts of the system whereby a false signal may be given to the sensor. Because of the wide range of fault current magnitude for which operation may be required

permanent desensitization of the sensor, to prevent unwanted operations from 'spill out', may not be satisfactory. This problem has been overcome by adjusting the operating level of the sensor according to the total amount of fault current. This was done originally by providing a restraining winding or electromagnet which carried the total terminal current, while the operating electromagnet carried only the differential current. This principle of 'bias' is now very widely used in different forms. One form, known as 'percentage bias', is applied to the circulating current protection of an item of plant as shown in Figure 6.7.

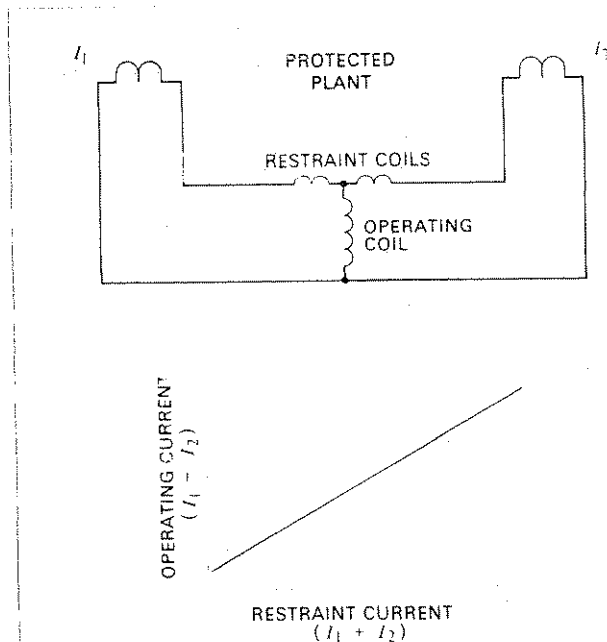


Figure 6.7 Percentage biased differential protection.

If the two zone boundary currents are  $I_1$  and  $I_2$  then:

$$\text{Operating quantity} = K_1(I_1 - I_2)$$

$$\text{Biasing quantity} = K_2(I_1 + I_2)$$

Suitable choice of the constants  $K_1$  and  $K_2$  ensures stability for external fault conditions despite measurement errors, while still retaining adequate sensitivity for operation under internal faults. The actual operating setting can easily be made far lower than could be permitted with an unbiased relay.

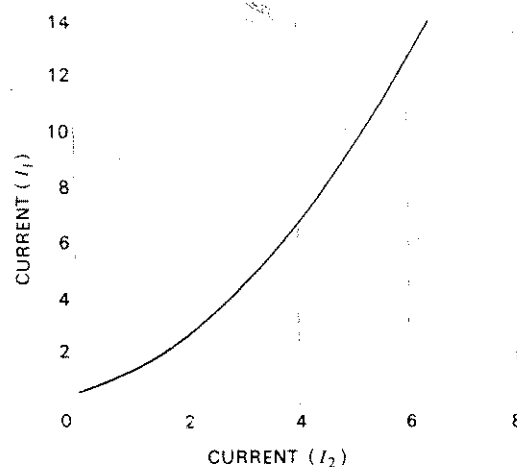


Figure 6.8 Typical bias curve for feeder protection.

When bias is applied to feeder protection, the zone boundary currents may not be summated; each relay may be biased only by the local fault infeed. It is usual to depict such bias characteristics in terms of the zone boundary currents, as in Figure 6.8, rather than their sum and difference as above.

Remoteness of the interconnection of feeder equipments can lead to phase displacements of primary as well as secondary quantities; it therefore becomes necessary to examine relay performance with relative phase displacement as well as magnitude difference. Characteristics are plotted as a polar diagram, one terminal current vector ( $I_1$ ) being fixed as a reference and the other ( $I_2$ ) plotted relative to it; the locus of the end of the second vector forms a closed area, within which the system remains stable.

In order to avoid the need for separate diagrams with differing scales when it is required to present the characteristics at widely differing current levels, it is usual to take the reference vector ( $I_1$ ) as unit length (for any current value), plotting the second vector in per unit values, that is, plotting the ratio  $I_2/I_1$ . Such polar characteristics are usually circular when all the circuit parameters are linear but become distorted when non-linearity occurs, perhaps because of saturation, as shown in Figure 6.9.

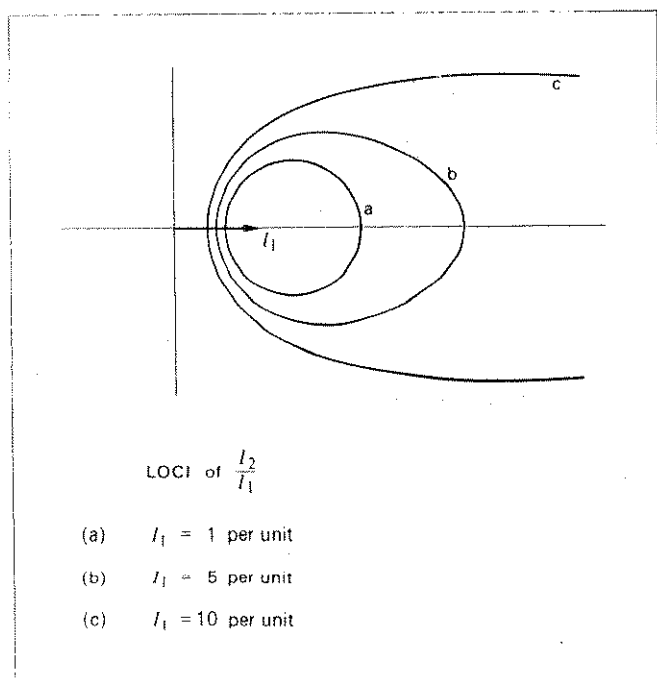


Figure 6.9 Typical polar characteristic of a differential feeder protection system.

When saturation is advanced, the locus boundary may not close but extend outwards apparently indefinitely. In this case the operation of the system is said to have passed into the phase comparison mode.

## 6.6

### PRINCIPAL TYPES OF RELAY

Armature relays are the simplest and also the most extensively used of all relays. They are of many widely different forms, and in application range from accurate measuring devices to auxiliary repeat elements, or relays performing a 'logic' function.

#### 6.6.1

##### Attracted armature relays

Most elements comprise an iron-cored electromagnet that attracts a movable armature which is hinged, pivoted or otherwise supported so as to permit motion in the magnetic field. The motion will be controlled by an opposing force

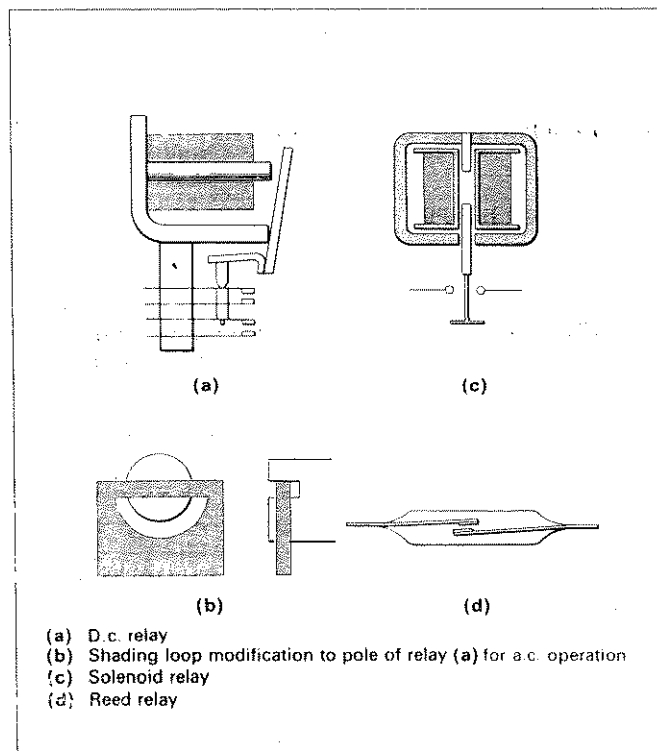


Figure 6.10 Typical attracted armature relays.

usually due to gravity or to a spring. Typical elements are illustrated in Figure 6.10.

In general the electromagnet will consist of a more or less U-shaped form, some portion of which carries an energizing coil. The moving armature is usually a light iron piece of simple form supported either on journal bearings or on knife edge pivots and free to move through a small distance so as to close the magnet circuit when the coil is energized. Either the armature carries a moving contact which engages with a fixed one when the armature operates or, alternatively, two contacts are pushed together by a rod attached to the armature. In many cases, multiple contacts are fitted and are arranged in a row or stack so that the above simple operation is carried out for all of them.

The theoretical force exerted on the armature is given by the expression:

$$F = \frac{B^2 A}{8\pi} \quad \dots \text{Equation 6.5}$$

where

$F$  = force

$B$  = flux density

$A$  = effective area of magnetic pole.

As the armature gap closes the flux density rises. This is inevitably so, since it is only by moving into the strongest field that the armature is enabled to do any work. It can be seen that as the flux density rises the magnetic pull increases rapidly, so that in order to reset the relay after an operation, the current must be reduced by an appreciable amount. The ratio of resetting to operating current level is known as the 'returning ratio'; it was formerly known as the 'differential'.

The effect of a ratio below unity is to give the device a snap action which is, in general, beneficial, as it gives positive action and good contact operation. However, a low resetting value may not always be acceptable. By preventing the armature from closing the magnetic circuit completely, the effect can be reduced. It can be further offset by spring control. This is illustrated in Figure 6.11. The variation of magnetic pull on the armature with armature position is shown by curve A. As the armature operates, the restraining spring is compressed and the restoring force increases,

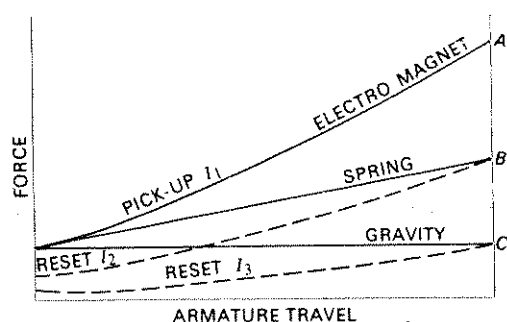


Figure 6.11 Effect of spring control on returning ratio.

as shown by the straight line  $B$ . The unbalance operating force in the closed position is therefore  $AB$ ; if a constant restraining force had been applied, corresponding to the horizontal line, the unbalanced quantity would have been  $AC$ . In order to permit the relay to reset, the current must be reduced below  $I_2$ , equivalent to the point  $B$  in the case of the spring-controlled relay and  $I_3$  in the case of gravity control. The latter has a lower resetting value, other conditions being equal.

It will be seen that if the slope of curve  $B$  is increased, that is to say, if the spring rate is increased, then the resetting value of the relay will be raised, but this will mean a reduction of the output force  $AB$  and reduced contact pressure. In fact, by using a sufficiently strong spring the relay can be given a proportional movement instead of a snap action, but will then have a correspondingly low contact making capacity. Typical relays may have a drop-out value of 25% of the pick-up value or alternatively 90% or even higher if special design attention is given to obtaining a high value. In the former case the relay will have high speed snap action and will be capable of doing a considerable amount of work in closing contacts, whereas the latter relay with a high drop-off value will tend to be relatively slow at current values marginally above setting and may have a reduced contact rating.

### 6.6.2

#### A.c. relays

Relays energized by a.c. will tend to vibrate, since, no matter how large the operating quantity, the flux must pass through zero every half cycle and at these points the armature will be released slightly from the magnetic pole. To eliminate this effect it is usual to split the magnetic pole and surround one half with a low resistance copper band. The eddy-currents induced in this loop cause a phase delay in the flux passing through the loop as compared with that in the other half of the pole. With this arrangement the flux does not come to zero on the whole face of the magnet pole at any instant, so that a hold-on force is always present.

Where a shading loop has not been provided, excessive relay vibration can be prevented by rectifying the supply. In this case the coil inductance maintains the current during the idle portions of the a.c. cycle.

Residual effects are greatest in d.c. relays. These sometimes show a slight variation in performance, depending on their immediate history, but this will only be noticeable if a very accurate check of setting is made.

Remanent flux in the magnet is important in connection with the drop-out settings of the relay and may in fact prevent the relay releasing.

In many cases, the relay armature is prevented from closing the magnetic circuit completely, on a non-magnetic stop. A gap of a few mils is sufficient to provide a demagnetizing m.m.f. which will destroy most of the remanent flux.

Alternatively, the relay core can be made from a magnetic material which retains only a little remanent flux; radio metal appropriately annealed is very successful in this respect and is applied in the design of type VAA auxiliary relays.

The design of such elements varies very widely, but typically, a small armature relay will operate with between 0.05 and 0.2 watts of coil energy and will pick up in between 0.01 and 0.04 seconds at five times the setting current. Operating values very different from the above may arise with special relays having large numbers of contacts, extra strong restraint to provide mechanical stability or some other special feature. For example, an eight contact trip relay designed to have a high stability against operation by mechanical shock may require as much as 80 watts of operating power.

### 6.6.3

#### High speed elements

By reducing the armature weight and the total contact travel it is possible to make a relay which is very much faster than indicated above. Reed relays, described in Section 6.6.5, are typical examples of this, being capable of operating in one millisecond at a moderate multiple of minimum pick-up value.

### 6.6.4

#### Solenoid relays

In this arrangement a steel plunger is attracted into a relatively long coil. It is usual for the magnetic circuit to be completed outside the coil by steel plates, so that the principle is generally similar to that of the armature relay, but the design is better adapted to providing a long stroke. The principle has been widely used in applications ranging from simple overload devices to the operation of mechanisms where a considerable amount of work has to be done.

### 6.6.5

#### Reed relays

These are a type of attracted armature relay. Two relatively stiff steel fingers are mounted so that their tips overlap and are normally separated by a small gap. When a magnetic field is applied, the two fingers are attracted together. The fingers are fitted with suitable contact making materials so as to be capable of closing a circuit. In the usual design, the fingers are enclosed in a sealed glass tube filled with hydrogen or an inert gas. An axial field can be applied by a coil surrounding the tube or by a permanent magnet placed alongside, allowing the device to be used as an electrical relay or as a proximity device in which the magnet is moved up to the tube to cause operation. Several such tubes may be inserted into a single coil to provide a multi-contact device and operating times of the order of one millisecond are obtainable.

### 6.6.6

#### Magnetically polarized armature relays

By combining a permanent magnet with the electromagnet circuit it is possible to construct a polarized relay. These relays are constructed in various forms to be either mono-stable (self-resetting) or bi-stable, in which case the relay has to be driven in either direction by applying the appropriate polarity of current. The energy available can be used to give normal fast operation for a considerable number of contacts, or, in the extreme case, operating times consistently less than one millisecond for a single contact.

A polarized relay designed for protective gear applications is shown in Figure 6.12.

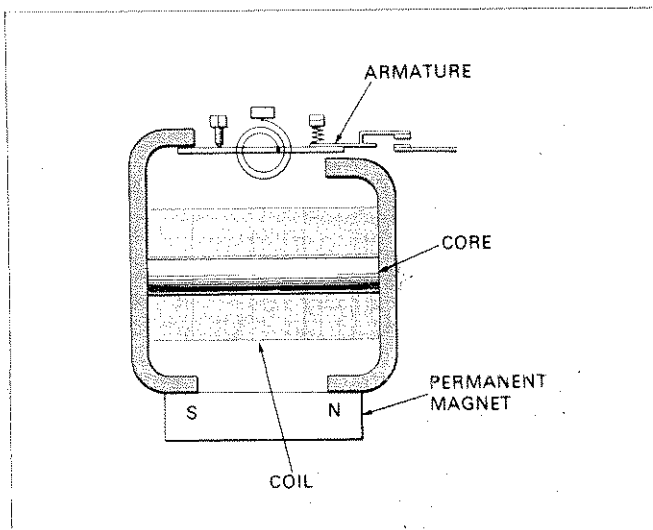


Figure 6.12 Typical polarized relay.

This relay can provide a robust operation with a minimum operating power of 3.5 milliwatts, and an operating time at 5 times setting current of 25–30 milliseconds. At higher multiples of setting or with a less sensitive relay, faster operation is obtainable, for example 15 ms with one watt input.

## 6.7

### MOVING COIL RELAYS

This classification covers rotary or axial type movements with permanent magnet field systems and dynamometer types with excited field systems.

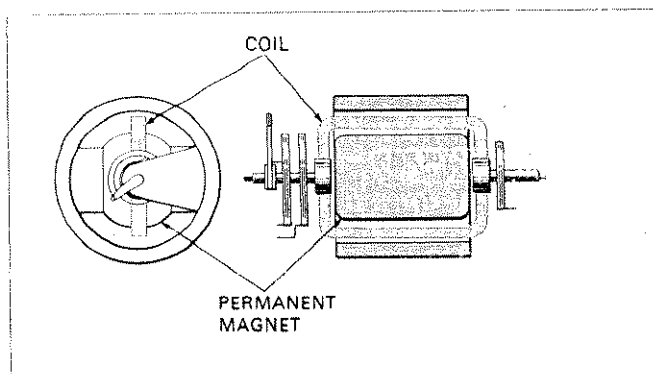


Figure 6.13 Rotary type moving coil relay.

#### 6.7.1

##### Rotary type moving coil permanent magnet relays

In this design, shown in Figure 6.13, a light pivoted coil is suspended in a radial field provided by a permanent magnet, and is free to rotate through a certain operating angle which may be either quite large, or limited to a few degrees to provide a typically short contact-travel relay. The movement is balanced, and the restoring force is provided by a spiral spring. In fact, in order to provide coil and contact connections, at least three spiral ligaments will be required which may also in combination constitute the spring control.

The magnetic field is usually arranged to be uniform over the operating arc, so with a given current the operating torque will be constant and independent of the coil position. It is therefore possible in a long-travel relay to provide a calibrated scale giving a range of setting adjustment. Alternatively, the movement of the relay coil may be limited to a small arc, but adjustment may be provided for the initial wind-up of the spring so that a similar range of setting value is possible.

The coil can be wound formless or on an insulating former. More usually the coil is wound on an aluminium or copper former which acts as a short-circuited winding and so provides a dynamic drag in opposition to the motion of the coil, because of the induced currents which are produced by such motion. This provides an efficient damping system which can effectively prevent over-swinging and, if made sufficiently strong, can provide a useful time delay.

As an alternative or supplement to the above action further damping can be obtained by providing a low resistance shunt path to the moving coil, whereby the back e.m.f. in the latter can cause a circulation of current in the local circuit of coil and shunt and so produce a damping force.

This type of relay can be very sensitive; for special applications 'galvanometer class' sensitivity can be obtained with a setting power of 0.02 microwatts.

With a proportional movement the returning ratio is nominally unity, but because of pivot friction, contact adhesion and so on, this can reduce to a reset value of 98% of the setting.

#### 6.7.2

##### Axial motion permanent magnet relays

In this design, shown in Figure 6.14, a cylindrical coil is suspended by leaf springs in the field of a concentric permanent magnet system. The coil is capable of moving axially over a short travel. Connections to the coil structure for the winding and contact circuits are made by ligaments exerting low restraining forces, as in the case of the rotary design. The coil is usually wound on a metal former whereby a damping force is obtained.

This design is less sensitive than the rotary type but is very robust. It has the advantage of having no bearings, but on the other hand is affected by gravity, so that the vertical alignment of the relay case is important.

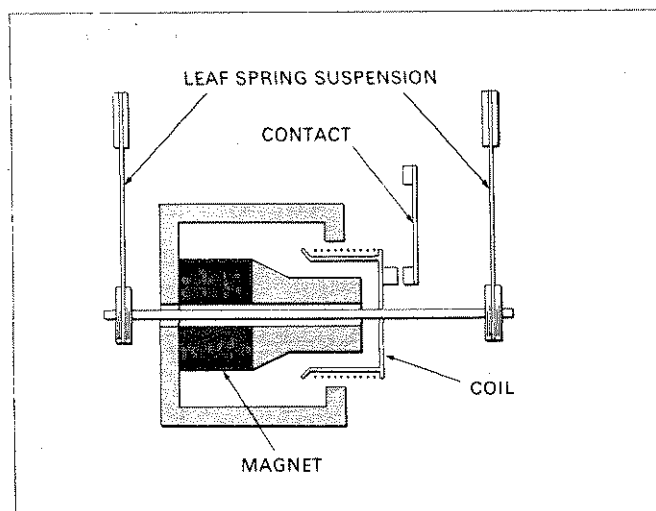


Figure 6.14 Axial motion permanent magnet relay.

#### 6.7.3

##### Dynamometer type

This type of relay is generally similar to the rotary type moving coil relay described in Section 6.7.1 but has an energized field which either may be iron-cored to provide a radial field as with the permanent magnet types, or may be entirely air-cored.

Whereas the permanent magnet type designs are essentially d.c. energized relays, which can only be applied to a.c. schemes by the use of rectifiers, the dynamometer pattern is a universal d.c. or a.c. relay. It is, however, much less sensitive, owing to the need to provide the field system flux electrically, and is therefore used only in special applications.

## 6.8

### INDUCTION PATTERN RELAYS

Induction pattern relays operate on the same basic principle as induction motors. Torque is produced by subjecting the moving conductor to two alternating fields which are mutually displaced both in space and time. The conductor may be a metal disc or cup. The two fields can be derived from one quantity by arranging to energize two electromagnets with an appropriate phase shift between them. Alternatively, the two magnets may be energized by separate quantities. In all cases the response is given by:

$$T = K \Phi_1 \Phi_2 \sin \alpha$$

where  $T$  = torque

$\Phi_1, \Phi_2$  are fluxes produced in the two electromagnets

$\alpha$  is the phase angle between  $\Phi_1$  and  $\Phi_2$

Typical induction relay electromagnet systems are shown in Figure 6.15.

The action may be explained by considering the eddy-currents produced in the disc or cup by each of the fluxes separately. In the system shown in Figure 6.15(a), the upper electromagnet will induce disc currents which will flow in front of the poles of the lower electromagnet, which produces a motor action. Similarly, the lower magnet will induce currents which will flow past the upper magnet pole and produce a corresponding motor torque. The resulting torque is the sum of the two, both of which are given by an equation of the form quoted above.

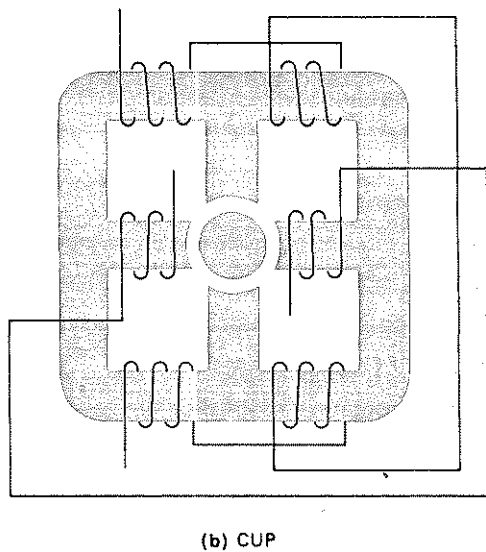
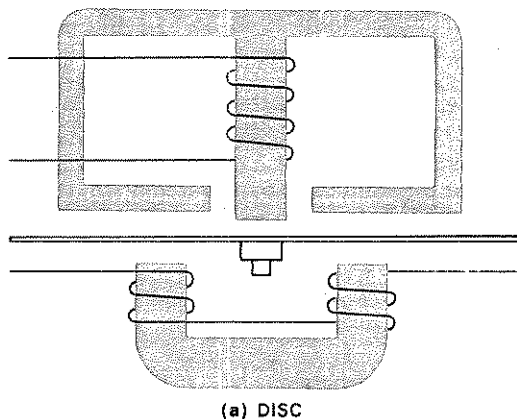


Figure 6.15 Product-type induction relays.

## 6.8.1

### Single quantity relays

Typical examples are overcurrent and overvoltage relays.

A C-shaped electromagnet is commonly used as shown in Figure 6.16.

The energizing quantity generates a flux across the magnet gap, in which is situated an aluminium disc. The area of the pole faces is subdivided into subsidiary poles, one of which is surrounded by a solid copper loop. The induced current circulating in this loop causes a phase displacement between the flux emerging from the shaded pole and that in an adjacent pole. The effect is to produce a laterally moving field which in sweeping across the relay disc produces a dragging force on the latter because of the currents induced in the disc. The driving torque is theoretically proportional to the square of the current value over the linear range of the electromagnet, but becomes modified from this simple relation at high current values owing to saturation of the magnetic circuit.

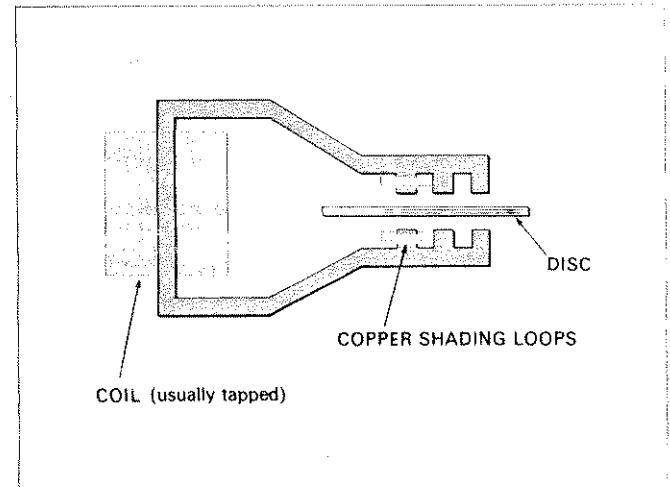


Figure 6.16 Type CDG induction overcurrent relay.

Motion of the disc is restrained by a spiral spring, the force of which must be overcome by the driving torque before any operation can begin; this determines the setting or minimum operating current of the relay.

The disc is further controlled by a permanent magnet which produces an eddy-current braking torque, this torque being proportional to the speed at which the disc rotates.

The response of the relay can be represented by the equation:

$$K_1 I^2 = S + \frac{K_2 d}{t} \quad \dots \text{Equation 6.6}$$

where  $S$  = spring torque  
 $d$  = distance moved  
 $t$  = time

$K_1, K_2$  = constants

This equation neglects disc inertia.

Also:

$$K_1 I_0^2 = S$$

where  $I_0$  = setting current. Hence:

$$K_1 (I^2 - I_0^2) = \frac{K_2 d}{t}$$

that is

$$t = \frac{Kd}{(I^2 - I_0^2)} \quad \dots \text{Equation 6.7}$$

The effect of the spring torque  $S$  is to make the characteristics asymptotic to the setting value instead of zero.

## Time control

In order to apply the relay in a graded system (see Chapter 9) it is necessary to be able to modify the time scale of the time/current characteristic. This can be achieved by control of the amount of disc movement, since the operating time is proportional to such movement at any given current value. If Equation 6.6 were completely accurate, time would be exactly proportional to distance and a single characteristic curve could be used with multiplying factors in proportion to the set travel as a fraction of the total. Actually, the spring torque varies over the angle of disc travel, so that the disc speed would vary and the time characteristic would change in shape for different values of  $d$ . This is corrected by giving the disc a non-circular shape, so that the radius measured through the electromagnet pole increases as the disc is rotated from the start to the 'contact make' position. The increase in radius provides the disc currents with a wider path and hence causes the driving torque to increase, the amount of this change being carefully proportioned to the spring rate. This compensation makes possible the calibration of the time adjustment as a multiplier for use with a single characteristic curve, over a wide range.

## Current setting adjustment

Taps on the coil are used to adjust current settings. It is normal to provide a 1 to 4 range of adjustment in seven steps, the taps being selected by the insertion of a single pin plug in the appropriate position on a 'plug bridge'.

Although wider setting ranges have been used in the past it is not in general desirable to do so because of the very poor coil utilization corresponding to the higher current taps; for example, for a ten to one range, only one-tenth of the coil turns would be in circuit for the highest setting and the coil rating as a multiple of setting would be low for this tap. This is of particular significance for earth fault relays for which high multiples of setting current may be relevant for all settings.

Tapping the coil can have repercussions on accuracy. Although in principle the relay operates with a given value of coil ampere-turns, in practice all turns are not equally effective. In addition to the useful flux, leakage flux is produced in the electromagnet which alters the flux density and hence the saturation level in part of the magnet iron circuit. This effect varies with the position of the active winding with the result that the curve shape is also affected.

The tap error is eliminated in the type CDG relay by winding the coil with a multi-conductor strip, the separate conductors being insulated from each other. The complete coil is formed by connecting the several conductors in series to form a single coil. The unit windings formed by each conductor are interleaved and each has its turns distributed throughout the whole coil space all being therefore equivalent magnetically. Taps are connected to the junctions between conductors so that the appropriate number of turns is involved for each, the magnetic effect being strictly proportional to the turns.

## Braking

It is important that the motion of the disc shall be limited to the correct amount, proportional to the energizing current and its duration; that is, the travel, due to kinetic energy, after current cessation must be as small as possible. The energy is minimized by keeping the disc weight low, using aluminium as the construction material. In addition, the operating and braking torques are made high so that stored energy is quickly dissipated. On the other hand, too much braking action can lead to unduly slow resetting; when this would be the case, part of the braking torque during forward movement is obtained from the electromagnet flux, provision for extra flux being made by

the addition of a third subsidiary pair of poles on the electromagnet pole faces.

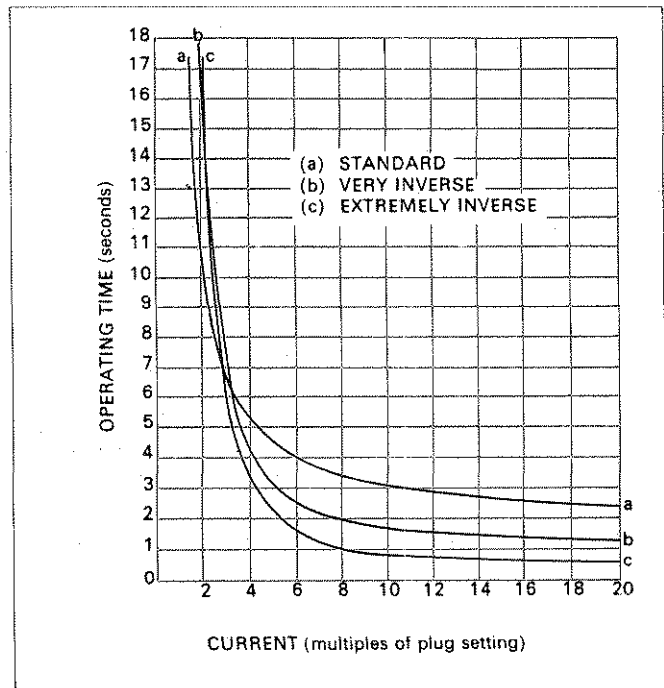


Figure 6.17 Time/current characteristics of overcurrent relays.

## Characteristic time/current curves

The majority of overcurrent relays have a characteristic which has been standardized in BS142 and is shown in Figure 6.17 (curve a).

Other characteristics are possible and have certain advantages in application (see Chapter 9). In particular, steeper curves which have been designated 'very inverse' and 'extremely inverse' are shown in Figure 6.17 (curves b and c). These curves are obtained by controlling the degree of saturation which occurs in the electromagnet; in general such relays have lower values of working torque.

Relays with overvoltage or undervoltage settings are obtained by providing a high-turn winding on a similar electromagnet, usually with the addition of a series resistor.

## Biased differential relays

Induction-type biased relays contain two electromagnets similar to those described above operating on a single disc assembly and arranged to develop opposed torques. The operation magnet will be supplied with the differential current, while the other will be energized by the biasing quantity. The windings will be proportioned to provide the desired bias ratio.

## 6.8.2

### Double quantity relays

When the two interacting fluxes in an induction relay are produced by separate input quantities the relay acts as a multiplier, as will be clear from the expression for torque given in Section 6.8. The electromagnet system may be similar to a watt-hour meter, Figure 6.15(a) or be of the form shown in Figure 6.15(b).

The upper electromagnet of the disc-type element is of low power factor, as are the two circuits of the cup relay. When these circuits are energized by a voltage, the flux produced lags the applied voltage by a large angle. This angle can be made effectively  $90^\circ$  by compensation arrangements; the torque developed is then proportional to power. This is the principle of the induction watt-hour meter.

For many protection purposes, the real power is not of significance, as it is desired to determine the direction of a

fault. Since the fault current phase angle will be approximately known, an observation of apparent power at the corresponding angle provides the required information. To this end directional relays are designed with a variety of connections and internal compensation arrangements, which are discussed at length in Chapter 9. The principal means of internal phase angle compensations are described below.

### Pole shading loop

For the meter type of element, a short-circuited copper band surrounding the active pole of the voltage electromagnet causes a phase delay in the flux which emerges to cut the disc. This effect is frequently used to compensate for the natural phase angle of the voltage-energized electromagnet in power measuring relays, but can also be used to provide a small additional phase shift giving a maximum torque angle of up to about 15° lag.

### Series capacitor and resistor

The addition of capacitor and resistor components in series with the voltage coil produces a leading phase shift which can easily be made more than 90°. Reversal of coil connections gives the effect of a lagging phase shift, as shown in Figure 6.18.

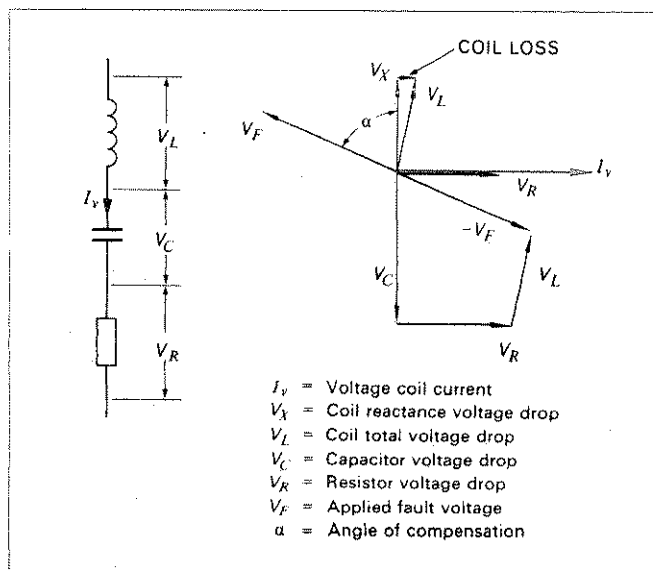


Figure 6.18 Vector diagram of phase shift applied to earth fault directional relays.

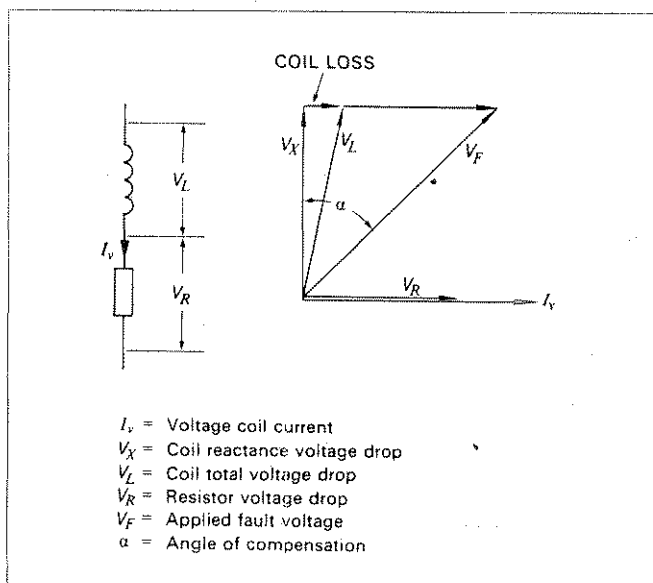


Figure 6.19 45° shift for phase fault elements.

This compensation is frequently used with earth fault relays, often to the extent of 60°–80°.

### Series resistor

Resistance in the voltage coil circuit causes a leading phase shift. The self-resistance of the coil produces a small shift of this type which represents an error in a purely wattmetric device and is corrected by a pole shading loop.

This principle is used in phase fault directional elements with a voltage selected to be in quadrature with that of the phase in question, as shown in Figure 6.19.

If the total circuit resistance and reactance values are equal, a leading shift of 45° on the applied voltage is produced, which, allowing for the quadrature voltage applied, gives maximum relay torque with a current lagging 45° behind the unity power factor vector position. The arrangement is called the 45° connection, or sometimes the 90–45° connection.

Alternatively, a lower resistive component may be used, giving 30° leading compensation, which produces maximum torque at a lagging angle of 90° less 30°, that is, 60°.

### 6.8.3

### Polyphase relays

A relay of the 'product' type can be arranged to receive three-phase voltages and currents. A design based on the induction cup and provided with eight poles is shown in Figure 6.20.

It will be seen that current and voltage poles are located alternately. Torque is produced in line with the product function of each adjacent current and voltage pole, the total torque being the sum of such individual torques.

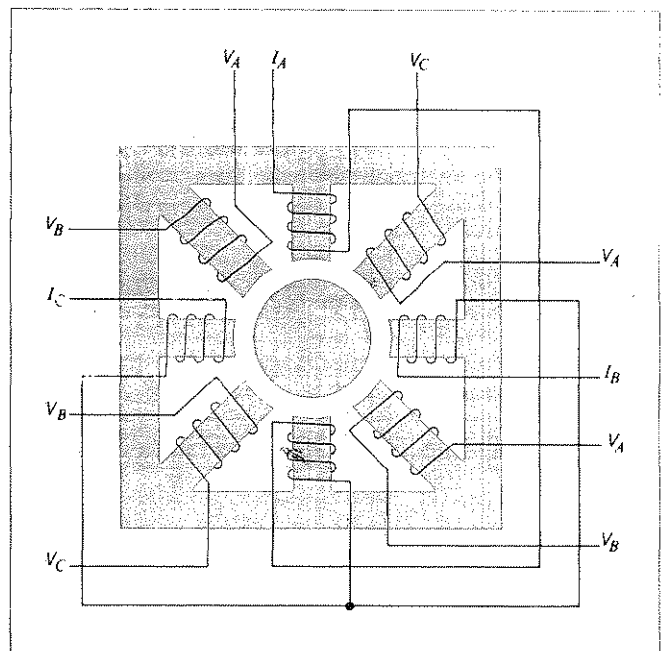


Figure 6.20 Polyphase induction cup relays.

### 6.9

### THERMAL RELAYS

Relays have been based on various thermal effects, the one most commonly used being the fact that metals expand when heated. Usually, the sensitive element consists of two layers of different metals intimately welded together. A strip of such 'bi-metal' material bends when heated because of the differential expansion of the two layers of metal.

In practical applications, the bi-metal strip may be initially straight or pre-formed into a spiral. The heat may be



applied by passing current through the bi-metal element, by a heating element wound on to the bi-metal strip or by radiation from an adjacent heating element.

Relays of this type are mostly used for overload protection; the length of the operating time delay will differ according to both the design of the thermo-sensitive element and heater, and the thermal mass and insulation which are incorporated. The thermal mass of the heater creates a problem in this design by causing a large overshoot effect if the current is reduced before tripping occurs.

The Sunvic hot-wire relay uses the direct expansion of a metal filament wound in a multi-turn flat formation between two parallel insulating bars, one of which is fixed, the other being carried on a pivoted frame subject to spring restraint which maintains the filament in tension. When a control current sufficient to heat the filament flows, the filament expands and allows the movable frame to tilt and close a contact. The whole assembly is contained within a sealed or evacuated glass tube.

The relay can operate with approximately one watt of control power; the operation in a high vacuum gives a considerable contact interrupting capacity. The operation is subject to an inverse time delay of a few seconds.

A thermo-couple and heater provide another basis for a thermal relay; in this case the moving element would be of the moving coil type.

Still another principle is obtained from the variation in resistance of a resistor due to temperature change. Although any variation would serve, specially heat-sensitive resistors called thermistors are available.

These can be combined with non-variable resistors to form a Wheatstone bridge which becomes unbalanced with a change in temperature from a chosen value. At this value, the sensing element, which may be of the moving coil type or an electronic circuit, is not required to carry current, receiving an input related only to any temperature deviation from this value.

The sensing element can therefore be of high sensitivity with a decisive response at the setting temperature. As the bridge circuit is static, it is easily made relatively robust. The input to the heater can be a simple or complex function; for example, in a relay designed to protect motors against both overload and unbalanced supply conditions, the input function is a blend of positive and negative sequence currents in a chosen ratio; see Chapter 20.

## 6.10

### DIFFERENT TYPES OF RELAYS

Many different types of relay have been evolved; some are now obsolete, but it may be useful to mention a few of them:

#### Motor operated relays

In these, a small electric motor drives a contact-making arrangement through reduction gearing. The relay may provide a time delay, control a complex sequence of operations, perform a repeated automatic reclosure of a circuit breaker or match the speed of a generator to the power system before synchronization.

#### Mechanical relays

These respond to pressure, fluid flow, liquid level and so on. The most widely used member of this class is the Buchholz relay, used to protect oil-immersed transformers. The relay, shown in Figure 6.21, consists of either one or two floats contained in a closed housing which is located in the pipe from the transformer tank to the conservator. Any fault in the transformer causes the oil to decompose, generating gas which passes up the pipe towards the conservator and is trapped in the relay; in the case of a

heavy fault, a bulk displacement of the oil takes place. In a two-float relay the upper float responds to the slow accumulation of gas due to mild or incipient faults, the lower float being deflected by the oil surge caused by a major fault. The floats control contacts, in the first case to give an alarm, in the second case to isolate the transformer.

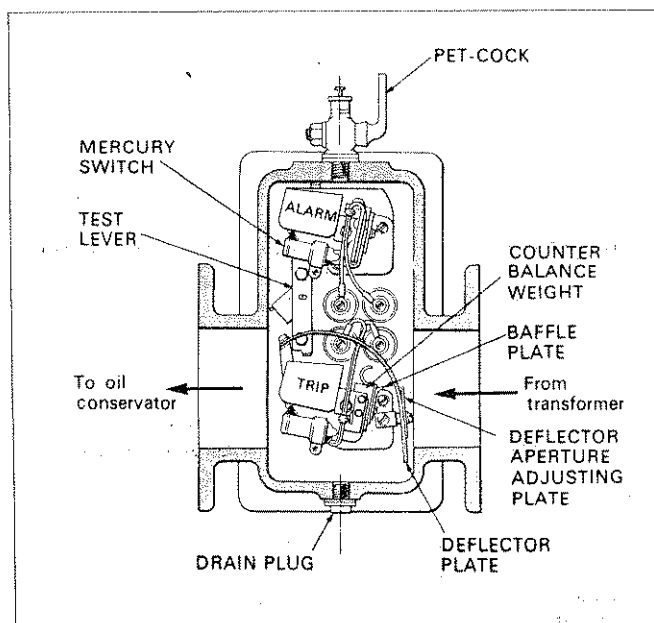


Figure 6.21 Typical Buchholz relay.

#### Temperature measuring relays

These are distinct from the thermal elements described in Section 6.9 although their action may sometimes be similar. When applied to regulate, they are often called thermostats, when used to give an alarm or trip they may be known as contact-making thermometers. They may be of the bi-metal type or depend on the expansion of a liquid in a sealed bulb connected by a capillary tube to a pressure sensitive device. Thermo-couple and resistance change principles are also used.

#### Time delay relays

There are many different designs of time delay relays. These may be classified according to whether they give short, medium or long time delays.

Short time delay relays will usually be of the slugged armature type. The slug is a solid copper cylinder surrounding part of the magnetic circuit. Flux changes are delayed by the eddy currents induced in this cylinder, causing delays in operating and resetting ranging from a few milliseconds up to a few seconds according to design and adjustment. Such relays must be d.c. energized.

Alternatively, thermal relays can be used to provide delays of a few seconds.

Medium time delays of up to 120 seconds are normally provided by relays in which an electromagnetic element operates against a controlling brake. The brake may be a dashpot, clock-work escapement, or eddy-current type. Some time delay relays, such as the type VAT, use eddy-current braking in which a metal drum rotates in the field of a permanent magnet.

When energized, the electromagnet picks up its armature instantly, thereby winding up a spring, the other end of which drives the eddy-current brake drum through gearing. The main axis on which the spring acts carries roller cams which operate the contact fingers. The time delay is adjusted by setting the position of the cams.

The purpose of the intermediate spring linkage is to make the operating time independent of the supply voltage.



The gear-train usually incorporates a ratchet which permits the relay to reset immediately when de-energized. The ratchet can be fitted reversed to give a time delay when de-energized or, in special cases, can be omitted.

Long time delay relays consist of a small motor, either d.c. or a.c. type, driving a contact-making assembly through reduction gearing. Where the gear ratio is high, that is, for long time settings, a friction clutch is incorporated to limit the torque which can be transmitted to the contacts or to the contact stop.

To reset after operation the motor may be reversed, giving a reset time equal to, or at least comparable to, the operating time. Alternatively, a clutch controlled by an electromagnet may be incorporated, to give an instantaneous reset when the relay is de-energized.

## 6.11

### CONTACT BEHAVIOUR

The output response of an electromechanical relay is denoted by the operation of a contact or contacts. These must make and break cleanly and decisively. The contact surface is usually rounded so that point or line contact is made; this increases the contact pressure, facilitating the breakdown of surface films and so enabling a low resistance contact to be made.

The surfaces must be clean and as free from tarnish as possible. Silver is commonly used for the contacting surfaces as it does not oxidize very readily, beyond forming a very fine film which is easily broken through. Silver sulphide may be produced by contaminated atmospheres; despite the lower specific resistance of this compound, it may build up to an extent which inhibits contact making. Fortunately the sulphide is soft and easily removed by the sliding motion of the contact faces.

For special purposes, contacts of gold, platinum, palladium, rhodium or tungsten may be used, or an alloy of two or more of these metals. The first four are suitable for ultra-sensitive relays since they are non-tarnishing, while tungsten, although of much higher resistance, is capable of withstanding a great deal of sparking without burning away.

It is important that dust, much of which is insulating, be excluded. For example, a particle of dry cement dust may be pressed into the surface of a contact and act as an insulating spacer, preventing actual metal-to-metal contact. If a gap of only one mil remains, flashover will not occur with normal low voltage supplies, that is, 250 volts or less, so that the contact will completely fail to close.

Failure may also occur because of a sticky film, either of tarry matter deposited from polluted air, or of resinous substances emanating from the insulating material. Care is taken in design to select insulating materials which give off the minimum of vapour. It will also be clear that electromechanical relays should be enclosed in cases which are effectively sealed; a breathing vent is desirable, however, with a filter built into the vent to trap dust and vapours.

Contacts should never be cleaned with emery paper or sand-paper, no matter how fine the grade, since particles of the abrasive may become embedded in the contact surface and subsequently prevent the contacts making. When badly burned, a contact may be cleaned with a smooth file and then smoothed and burnished.

For the same reasons cleaning powders or polishes should never be used. The contact may be cleaned with a pure solvent, such as trichlorethylene, applied sparingly with a fine brush; a second brush must be used to clear away excess and dry the contact. No contaminated solvent must be put back into the bottle, or the solvent will soon become more harmful than otherwise.

The interrupting capacity of contacts is a complex matter.

The current and voltage of the circuit, whether d.c. or a.c., the power factor of the circuit, and the speed of contact separation all bear on it. It may be noted, however, that:

a. A resistive load is comparatively easy to interrupt but may impose difficult 'making' conditions because of the rapid rise of current, the maximum value being reached before the contact surfaces have ceased to move relative to each other.

b. An inductive load is difficult to interrupt; however, it imposes a relatively easy 'making' duty, provided that contact 'bounce' and 'chatter' are both negligible, because the current grows more slowly; this gives the contact time to stabilize before a high current value has to be carried. This fact enables a light high speed contact to 'make' a substantial inductive load, provided circuit interruption is arranged by some other means.

c. A capacitive load provides extremely difficult 'making' conditions because of the high current surge that flows to charge the capacitor. If no resistance or inductance is connected in series with the capacitor, the contacts are likely to be seriously damaged. Even quite a small capacitance can cause the contacts to weld together. In the case of an induction or moving coil relay, in which the resetting torque is provided by a light spring, a weld sufficient to prevent resetting can be caused by charging a capacitance of 0.002  $\mu$ F to 250 volts.

d. Other loads, such as metal filament lamps, small direct-on started motors and so on, may give rise to initial high currents at circuit closure. Unsatisfactory contact performance can often be traced to unsuspected initial current surges of this nature, of too short a time constant to be observed on an indicating instrument.

In the majority of cases, protective relays are required to 'make' circuit breaker trip circuits but not to break them; usually they would not be capable of so doing and the clearance of the circuit is achieved by an auxiliary switch driven by the circuit breaker mechanism.

## 6.12

### COIL RATING

A rated maximum continuous current value can be assigned to a coil according to its class of insulation and the consequent maximum desirable temperature rise.

This value is the most significant rating for any coil which is energized continuously, such as in an undervoltage relay, the voltage coil of a directional relay, or in many auxiliary d.c. control relays.

A current coil will have to carry fault currents, for the duration of which the coil is heavily overloaded. Because of the short duration, there is no need to design the coil to be continuously rated at these high values but the short-time rating is important. Measurement of the true temperature rise during these short periods of intense heating has its difficulties, but the assumption can be made that all the heat generated remains within the copper, there being insufficient time for any appreciable dissipation to take place. On this basis the temperature rise for a given energy input can be calculated from the mass of the wire. Since the heat energy remains where it is released, the length of the winding is unimportant and the temperature rise can be calculated knowing only the wire diameter, the current and its duration.

Under the conditions postulated, the amount of heat stored is not large and subsequent cooling is also quick, so that the duration of a high temperature condition is very short. In consequence a maximum temperature rise of 200°C is considered to be permissible. On this basis the following table relates the current density in the conductor with the permissible time of energization.

| Current density           |                         | Permissible time of energization (seconds) |
|---------------------------|-------------------------|--------------------------------------------|
| (amperes per square inch) | (amperes per square cm) |                                            |
| 150,000                   | 23,250                  | 0.5                                        |
| 106,000                   | 16,430                  | 1.0                                        |
| 75,000                    | 11,620                  | 2.0                                        |
| 61,000                    | 9,450                   | 3.0                                        |

### 6.13

#### COIL CONNECTIONS

The potential between a coil circuit and earth will give rise to a small leakage current since the insulation resistance is never infinite. In the case of enamelled wire, the coating is never without occasional minute 'pin-hole' faults. The leakage current is concentrated at these points and, if the coil potential is positive to earth, will cause electrolytic corrosion of the wire.

Although the leakage current may be extremely small, the accumulated effect focussed by a pin-hole to one point can corrode through a fine wire in an unacceptably short time. Any attempt to improve the insulation can delay but not prevent failure. The trouble is, however, completely overcome by ensuring that the coil is held at zero potential or negative to earth while not energized. The following practices are commonly used in switchboard design:

**a.** All coils are connected to the negative pole of the station battery, which is not earthed. Controlling contacts are inserted in the positive lead to the relay coils. The battery will have a distributed leakage to earth, so a mid-position on the battery will be at earth potential. An earth fault indicating scheme, involving the connection of a high resistance from each pole to earth may also be applied; this will help to locate earth potential at the centre of the battery. While not energized the relay coil will be negative to earth under normal conditions and can never become positive.

In certain cases, for instance busbar protection, double pole switching of tripping relay circuits is used to give extra security against accidental tripping. The contacts in the negative lead are then bridged by a high resistance that cannot pass a current capable of causing relay operation, but which will hold the relay coil at the potential of the negative supply lead.

If continuously energized, a relay coil is much less likely to be attacked, as the self-heating effect will keep the surface drier.

**b.** The positive pole of the battery may be earthed. This is common practice for communication and allied systems power supply.

**c.** The positive pole of the battery may be connected to earth through an auxiliary power unit that maintains this pole negative to earth by a small amount, the negative pole being at still lower potential. By this means coils may be connected to either pole of the battery, as convenient. The biasing unit usually includes an alarm relay and a high resistance, to give alarm of an earth fault on the battery wiring, and to limit the earth fault current to a low value.

### 6.14

#### MECHANICAL STABILITY

Relays are delicate measuring devices, yet the importance to the power system of their absolute reliability, coupled with the hazards of their environment, make it desirable that they should be mechanically stable and resistant to shock and vibration.

### 6.15

#### MAINTENANCE

Once correctly installed in satisfactory ambient conditions,

protective relays need little maintenance. Periodical checking is desirable; the frequency of this will depend on circumstances and be decided by experience. Under bad service conditions, such as in a dusty, damp or corrosive atmosphere, testing may be needed every few months. On the other hand, in good conditions, little deterioration may be detectable after five years and check testing can be substantially reduced. However, should the relay become defective, by the open-circuiting of a coil or connection for example, this fact may not be discovered until the next test, and the circuit may have been unprotected for most of the inter-test interval. An annual test may be regarded as a satisfactory compromise.

If arrangements are made to carry out a 'functioning test' by push-button switch at regular intervals, more detailed examination and testing can be less frequent under good conditions.

Chapter 23 deals with testing in more detail.

# Static relays

- 7.1 Introduction.
- 7.2 Circuits using analogue techniques.
- 7.3 Digital techniques.
- 7.4 Output and tripping circuits.
- 7.5 Accommodation of static relays.
- 7.6 Electrical interference.
- 7.7 Quality control and production testing.
- 7.8 Future trends.

## 7.1

### INTRODUCTION

Static techniques for power system protection are now well established and have been developed over a period of more than twenty years. The designs which first gained wide acceptance were based on the highly reliable silicon planar transistors but such is the pace of semiconductor device development in the last twelve years that linear silicon integrated circuits, digital gate and logic circuits, custom built medium scale integrated (MSI) digital circuits and latterly, memories and microprocessors have also been incorporated into the designs.

Use of these components and static techniques has made it possible to design high performance and more sophisticated characteristics into relays which are necessary to meet the requirements of modern complex power systems. In addition to the new or improved characteristics the further advantages of speed, sensitivity, freedom from maintenance, immunity to shock and reduction in size can also be gained.

It is now possible for static relays to be designed to replace all the functions previously performed by electromechanical designs. However, there are some functions, for example that of multi-contact attracted armature relays and simple induction disc relays, which will co-exist with static relays for some time because of the inherent simplicity of their electromagnetic designs.

The introduction of static relays posed a number of new problems for the manufacturer:

- a. The manufacture of electronic equipment necessitates using numerous components made by other manufacturers and rigorous quality control tests are necessary, before they are used, to ensure reliable in-service equipment life.
- b. The use of increasingly complex devices and circuitry has made automatic production test equipment necessary at all stages of production.
- c. The sensitivity of high-speed digital circuits has accentuated the problems of operating reliably in the presence of high amplitude electrical interference generated in high voltage switchyards.
- d. A reliable d.c. power supply for electronic measuring circuits has to be generated from available power sources.

The design of static protection initially developed along two distinct paths:

- i. Separately housed discrete relays having a single or a low number of functions.

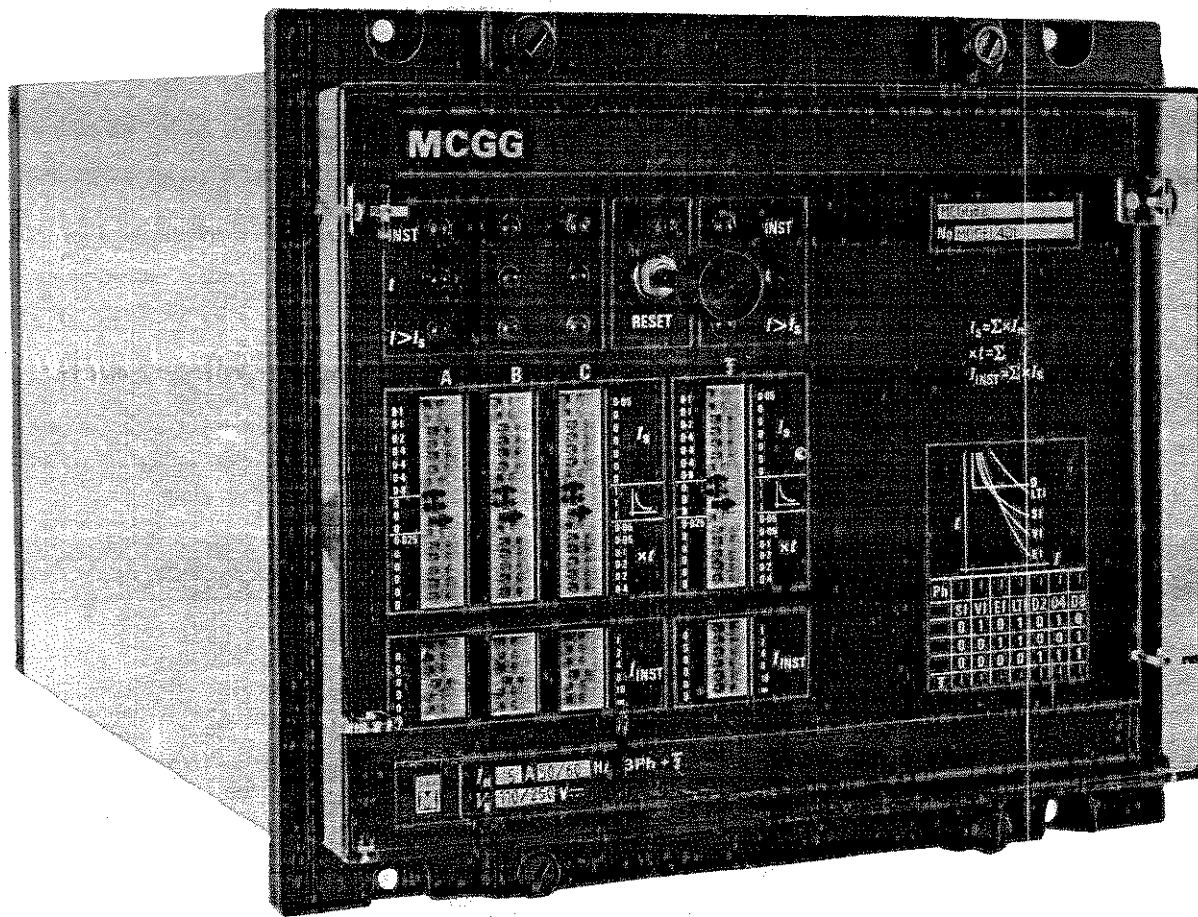


Figure 7.1 Microprocessor based, three phase and earth fault static overcurrent relay Type MCGG.

These relays are broadly similar to electromechanical relays in function and often can be used as direct substitutes. Figure 7.1 shows a phase and earth fault overcurrent relay designed to replace electromechanical disc relays in distribution protection schemes.

ii. Complex multifunction schemes, where a number of related measuring elements are interconnected at electronic levels, scheme logic is processed by digital logic or microprocessors and common outputs such as indication, trip and alarm signals are given. This enables full advantage to be taken of the inherent speed of the measuring elements and the digital logic circuits. A common power supply module with some regulating capability usually provides power to the complete protective scheme typically comprising various plug-in modules in a rack mounted case.

Figure 7.2 illustrates a current differential feeder protection scheme comprising multiple modules in a composite housing.

## 7.2

### 7.2.1 Time-delayed overcurrent relay

As the development of static relays progressed, a small number of circuits were applied repeatedly in designs. This is similar to some extent to the way in which a small number of basic electromechanical elements are used for differing applications in electromechanical relays.

The power system input quantities to measuring relays, such as current, voltage, phase angle, and power, are analogue quantities. These are usually compared singly or in some combination with a reference 'setting' level and a digital (yes/no) decision is given as a result of this measurement.

### 7.2.1

#### Time-delayed overcurrent relay

Basic circuits often used are:

- A.c. to d.c. converter circuits for converting a.c. input quantities to d.c. for subsequent measurement and comparison.
- Level detectors which compare the input analogue quantity with a set level and give a digital output command when the set level is exceeded.
- Timers which give upon command a time delay which is either constant or proportional in some way to the analogue input quantity.

Each of these circuits forms a part of the time delayed overcurrent relay shown in the block diagram in Figure 7.3. The a.c. current is converted to a d.c. voltage by means of a current transformer of suitable ratio, a bridge rectifier and a resistive shunt load. This voltage is compared with a set level by level detector 1 which gives a start command to the timer when this level is exceeded. This timer provides either a fixed time in the case of definite time relays or a time inversely proportional to the magnitude of the input cur-

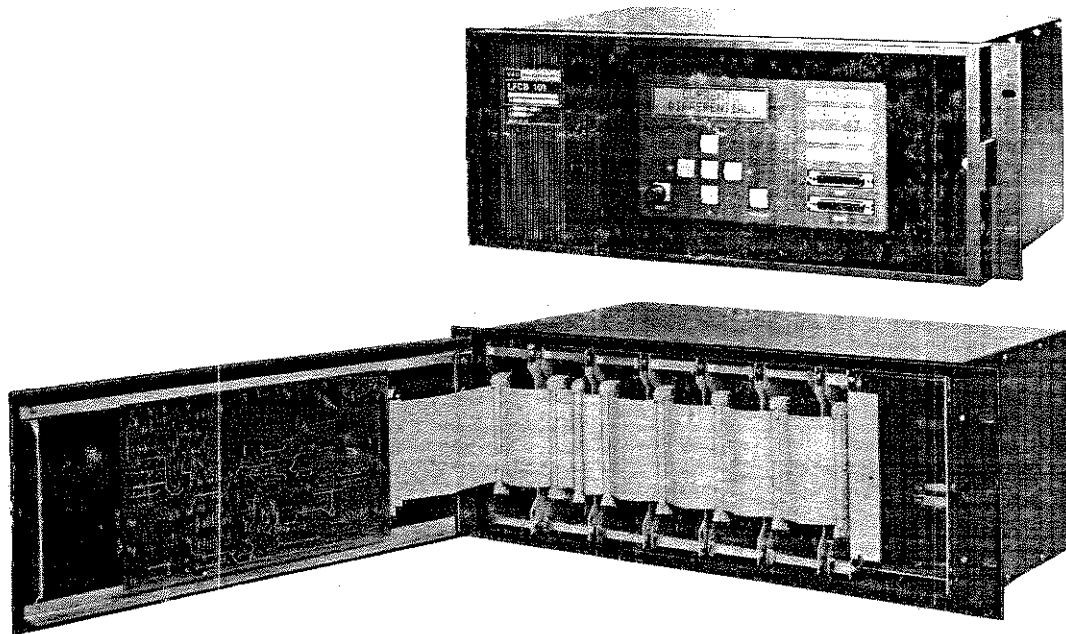


Figure 7.2 Current differential feeder protection scheme.

rent, in which case a curve shaping circuit is required. The timer usually charges a capacitor such that when the charge reaches the level set on level detector 2 the latter gives a signal to the output switching circuit. Instantaneous operation for short circuits can be obtained by means of a third level detector which bypasses the time delay circuit.

A single phase relay can be converted easily to a three phase design by using either circuit shown in Figure 7.4. In Figure 7.4 (a) each of the three phase currents is converted to a voltage and the bridge rectifiers work as gates such that the output is rectified and is the highest instantaneous voltage from the three shunt loads. In Figure 7.4 (b) the secondary currents are gated and the output current is the highest instantaneous current, which is then rectified and

fed to the output shunt load which converts it to a voltage. If either one of these circuits is used on the input of a static overcurrent relay it will respond to the highest of the currents in the three phases.

Although early designs used transistors, analogue measuring circuits now universally use the integrated circuit operation amplifier shown in Figure 7.5. This is a high gain, d.c. coupled amplifier which amplifies the voltage difference between its input terminals. The ideal operational amplifier is characterized by:

- i. Infinite voltage gain.
- ii. Infinite input impedance.
- iii. Zero output impedance.

So using it to measure an analogue quantity imposes no

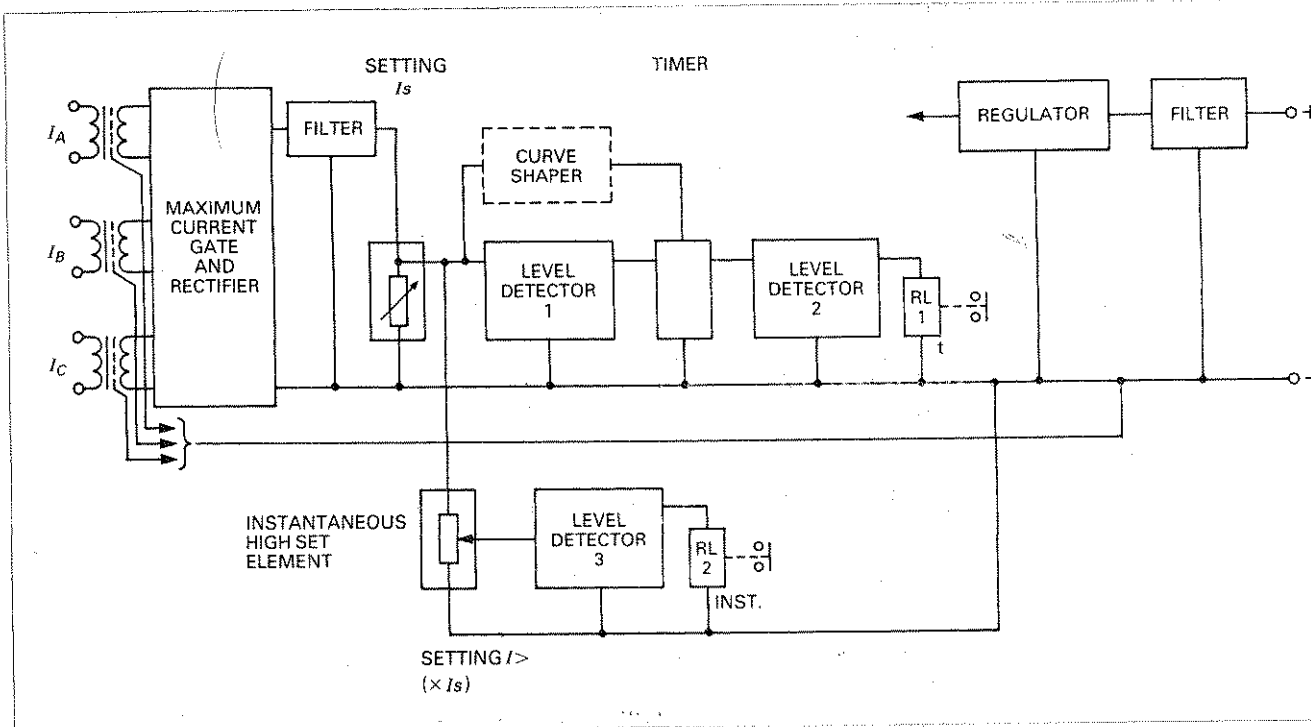


Figure 7.3 Time-delayed overcurrent relay with instantaneous highset element.

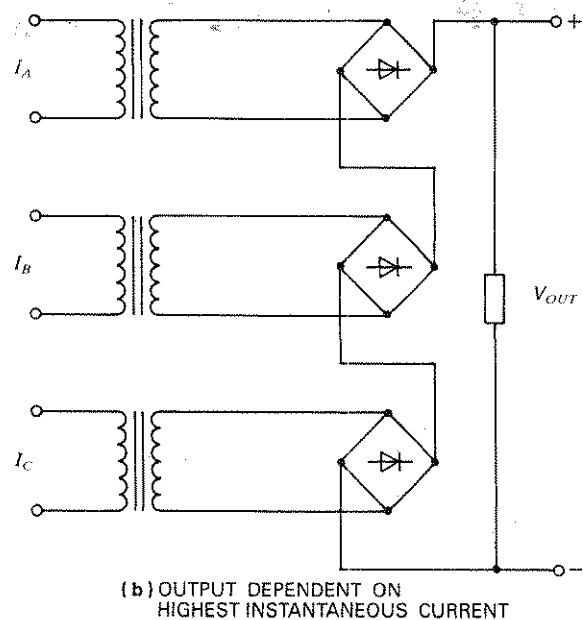
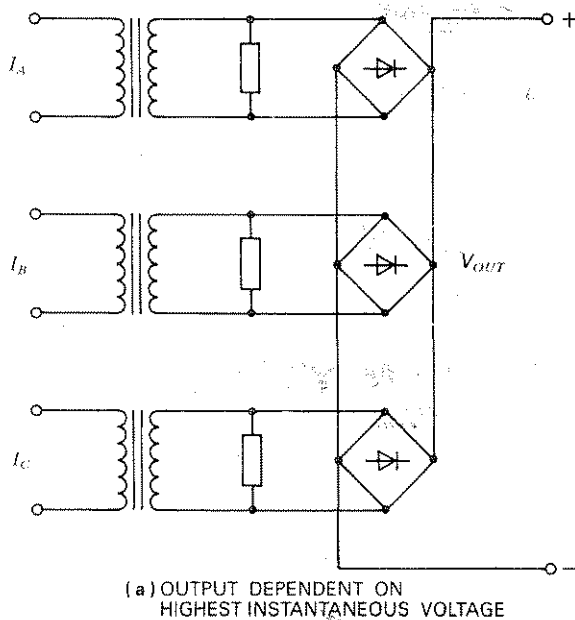


Figure 7.4 Three phase gating circuits.

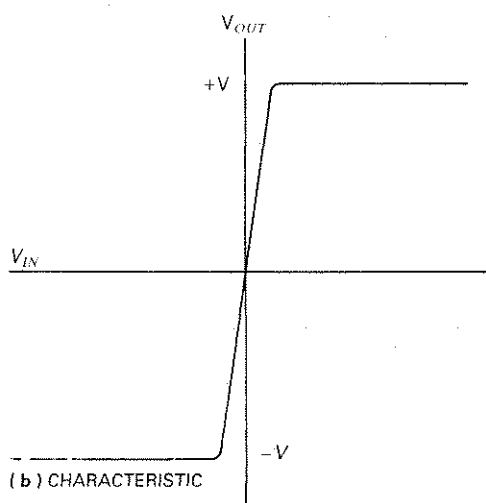
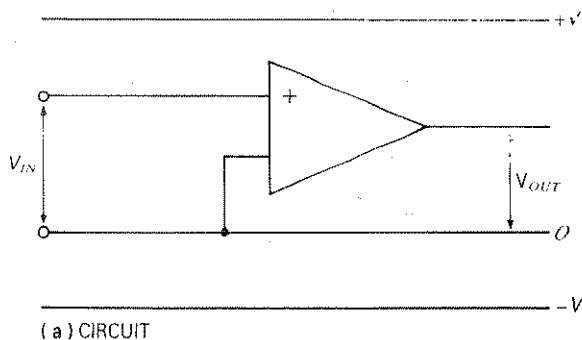


Figure 7.5 Operational amplifier.

burden on the measured quantity and its output can drive substantial loads.

The operational amplifier can be used in a number of basic relaying circuits.

## 7.2.2

### Level detector

The inverting input of the operational amplifier is connected to a reference voltage and the input voltage is compared with this as shown in Figure 7.6. If the input voltage is lower than the reference voltage the output voltage remains low, but the output switches to the positive d.c. supply rail when input voltage exceeds the reference. Figure 7.6 (b) shows the input and output voltages when the level detector is extended to form a timer, using the resistance-capacitance input circuit shown in dotted lines in Figure 7.6 (a). The operating time can be varied by varying the resistor in the  $RC$  circuit or the reference voltage.

## 7.2.3

### Polarity detector

In this circuit, shown in Figure 7.7, the inverting input of the operational amplifier is connected to the zero voltage rail, with the d.c. supply rail voltages being equally disposed about it. The input signal is a sine wave which is converted to a square wave by the high gain of the amplifier. The output signal is essentially digital having only two states, high and low, corresponding to the polarity of the input signal. The transitions between the polarities (zero crossings) are clearly defined and are almost independent of the amplitude of the input signal.

## 7.2.4

### Integrator

Another circuit commonly used in static relays is the integrator, which may also be based on an operational amplifier, as shown in Figure 7.8. The input current having the value  $E_1/R_1$  flows in the capacitive feed-back loop through  $C$ .

The inverting input terminal is at the common earth potential, so the voltage across  $C$  must be equal and opposite to

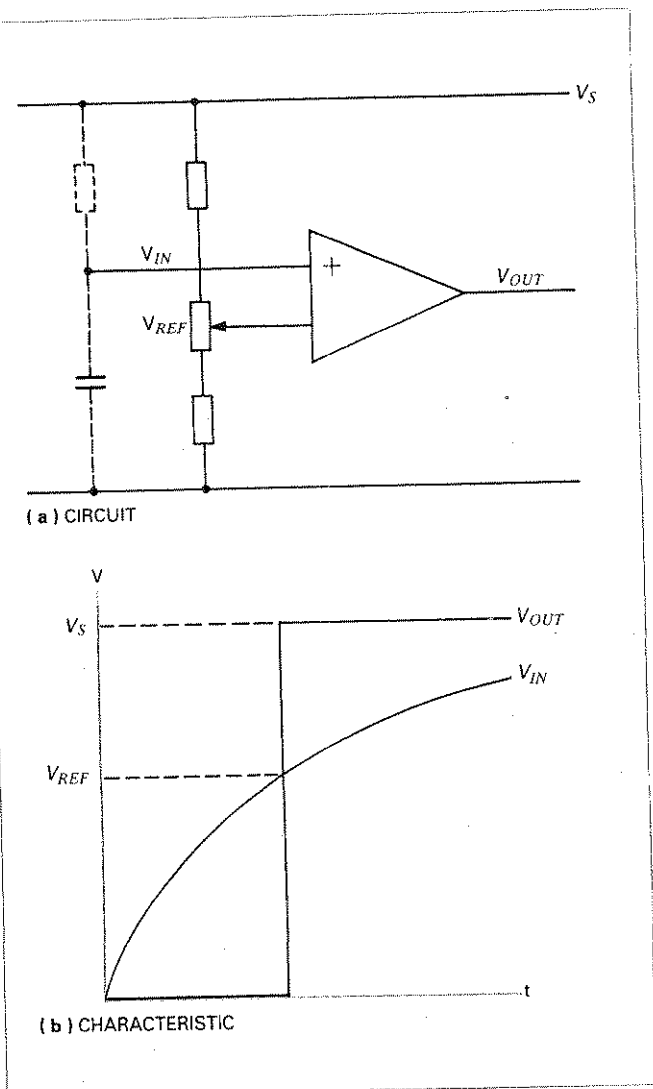


Figure 7.6 Level detector.

$E_0$  the output voltage.

$$\text{Voltage on } C = \frac{1}{C} \int i_1 dt = \frac{1}{C} \int \frac{E_1}{R_1} dt$$

$$\text{hence } E_0 = -\frac{1}{R_1 C} \int E_1 dt$$

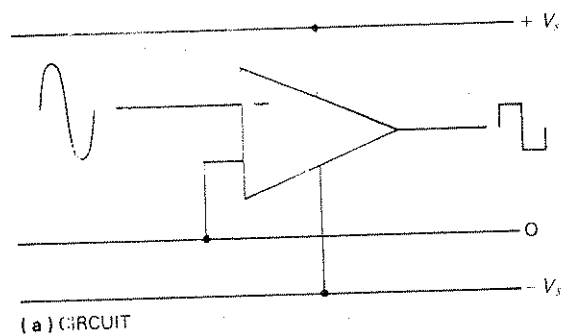
The output voltage  $E_0$  is therefore proportional to the integral of the input voltage  $E_1$ .

This circuit can be used as a timing circuit where the rate of change of the output voltage is proportional to the magnitude of the input signal. The curve shaper in the inverse time overcurrent relay shown in Figure 7.3 is an example of this application.

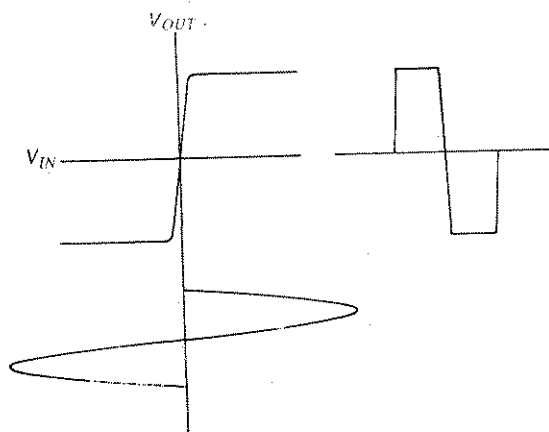
### 7.2.5

#### Application to distance relay characteristics

Figure 7.9 shows a mho characteristic as used in distance relays. It can be seen from the diagram that if the phasors  $V - IZ$  and  $-V$  are compared for a phase relationship of  $\pm \pi/2$ , an operating locus will be obtained which is a circle passing through the axis of the diagram and having a diameter of  $IZ$ . Figure 7.10 shows a phase comparator in diagrammatic form using linear integrated circuits. The two sinusoidal signals to be compared for phase,  $V - IZ$  and  $-V$ , are fed to operational amplifiers  $IC1$  and  $IC2$  respectively. The diagram shows the waveforms of the signals as they are processed through the phase comparator circuit.  $IC1$  and  $IC2$  are working on open loop (no feed-back) with maximum signal gain.



(a) CIRCUIT



(b) CHARACTERISTICS

Figure 7.7 Polarity detector.

Their function is to provide at their outputs a translation of their input signal polarities in terms of a square waveform of fixed amplitude independent of the amplitude of the input sine wave signals, but changing polarity at the same instant. The two square wave signals are then fed to a coincidence detector which gives a negative signal for both positive and negative coincidence of the input signals, and a positive signal for non-coincidence.

For a phase comparator working between comparison limits of  $-\pi/2 \leq \theta \leq +\pi/2$  the output of the coincidence detector will be a square wave of twice the frequency of the input signals with a unity mark/space ratio, when the comparator is on the boundary of operation, that is, when the angle between the input signals is  $+\pi/2$  or  $-\pi/2$ . The next step in the process is to convert this phase information to amplitude information and operate a level detector to give a trip signal. This is effected by feeding the signal to  $IC3$  which is connected to perform an integrating function. The integral of a square waveform is a triangular waveform. For a condition just inside the boundary of operation the mark/space ratio becomes just greater than unity, and therefore the rising ramp of the triangular wave is active for slightly longer than the falling ramp.

The resultant d.c. level of the wave therefore rises towards the positive rail potential as shown. The rising level is detected by a level detector working in a Schmidt trigger mode. It has defined pick-up and reset levels which are arranged to eliminate transient over-reach and also hunting on the output signal.

### 7.3

The outputs of all static relays are digital, that is they perform some kind of switching function. Therefore the analogue input signals are converted to digital signals at some stage.

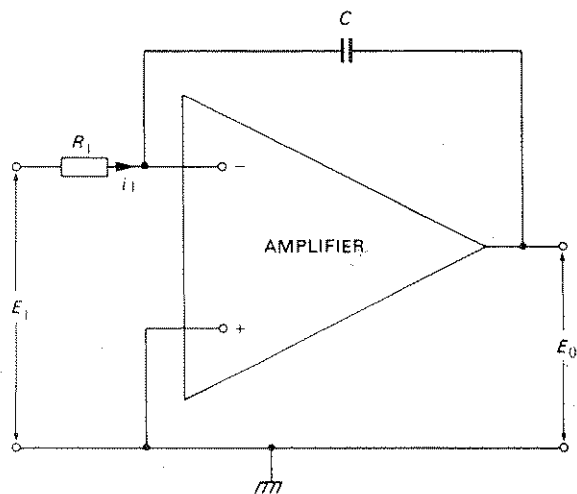


Figure 7.8 Integrator using an operational amplifier.

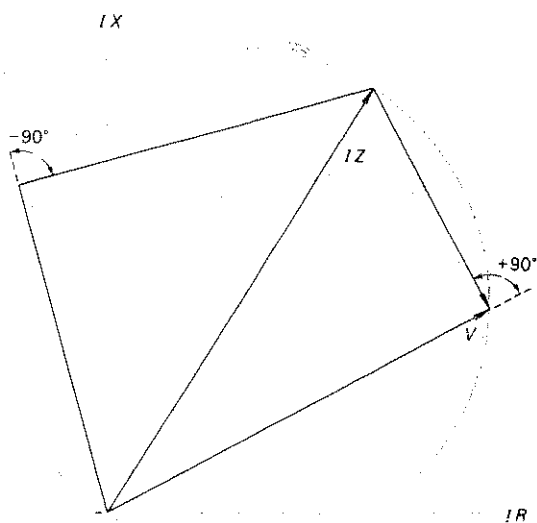


Figure 7.9 Measuring characteristic of mho relay.

With the rapid development of digital integrated circuits, logic gates, microprocessors and microcomputers, relaying circuits are increasingly using digital techniques.

Digital techniques provide an attractive solution for all forms of relaying requirements which can be reduced to a series of logical functions.

Analogue signals such as voltage and current can be con-

verted to digital signals by means of voltage to frequency converters or analogue to digital converters (ADC's). The resultant digital signal can be processed either by discrete logic or by a microprocessor. Generally discrete logic can perform a large number of relatively simple operations in parallel, whereas a microprocessor can perform highly complex logical tasks but is not ideally suited to parallel operation.

### 7.3.1

#### Distance relay digital sequence comparator

In general speed and security are not compatible. The distance relay shown in Figure 7.11 employs discrete logic to form a high speed digital sequence comparator which obtains its security by a signal verification principle. If this verification is not obtained it is assumed that noise may be distorting the signal and more information is demanded before a tripping output signal is permitted.

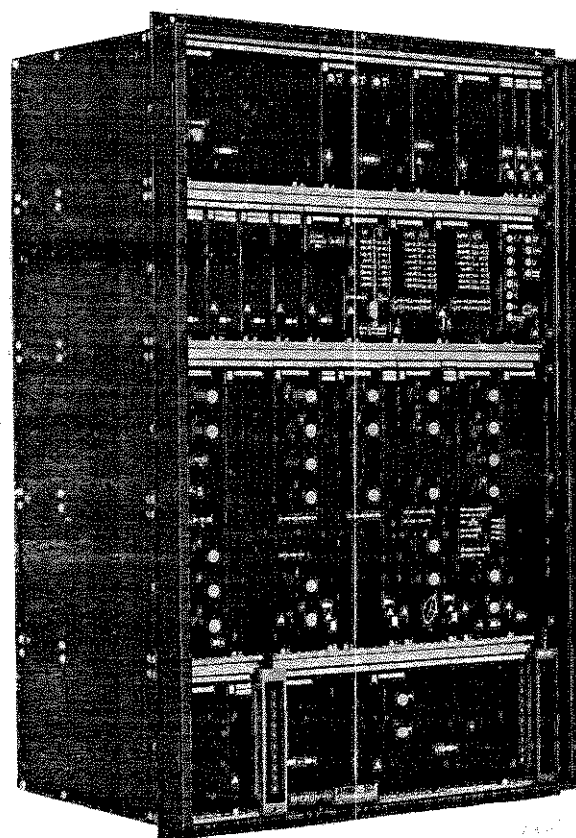


Figure 7.11 'Micromho' distance relay.

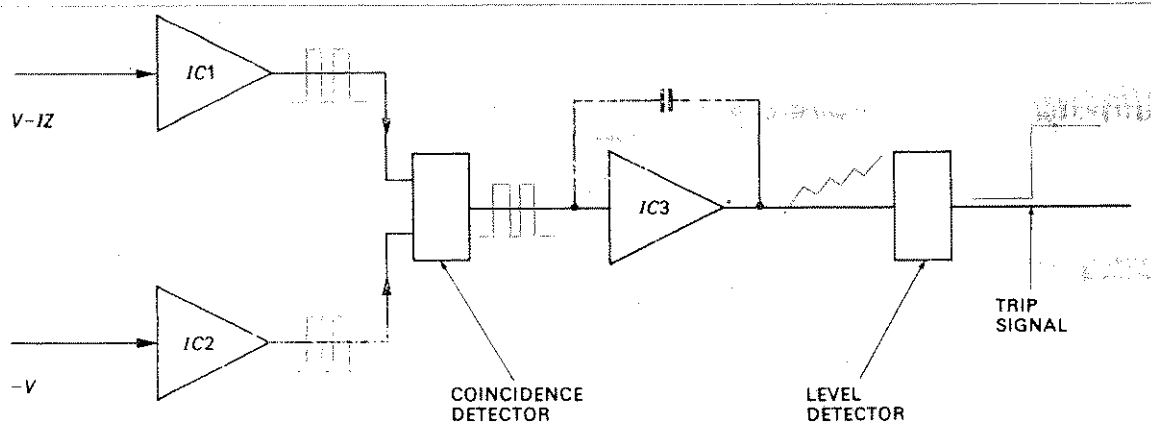


Figure 7.10 Phase comparator application to obtain mho characteristic, using the block average principle.



The phase comparator uses a phase sequence technique employing custom designed bipolar IC's. To eliminate the effects of travelling-wave distortion of the voltage signal, a second-order low-pass filter with a cut-off at 500 Hz preconditions the voltage signal.

For a mho characteristic the phase comparator has the input quantities  $A$  and  $B$  shown in Figure 7.12 such that

$$A = V - IZ$$

$$B = V \angle -\pi/2$$

and the criterion for operation is that

$$\pi > \arg \left( \frac{B}{A} \right) > 0$$

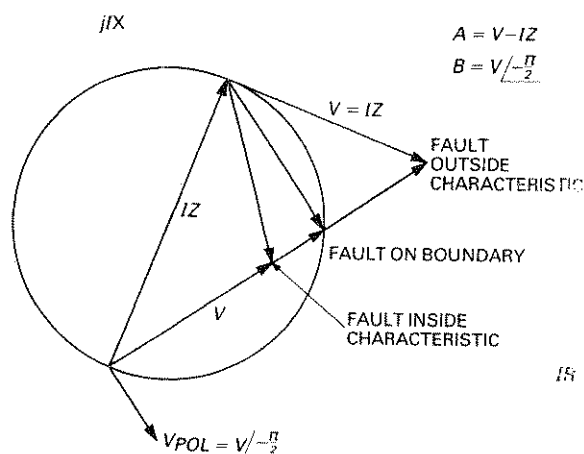
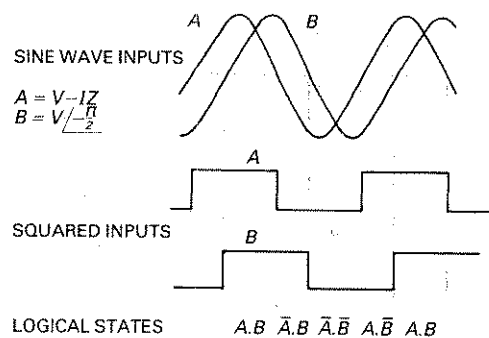
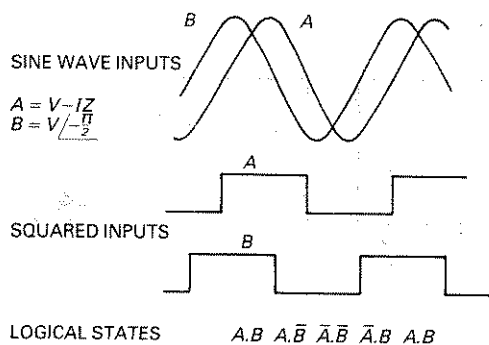


Figure 7.12 Sequence comparator voltages for mho characteristic.



(a) RESTRAIN CONDITION



(b) OPERATE CONDITION

Figure 7.13 Sequence of logic variables for 'Micromho' comparator.

that is, that  $A$  lags  $B$  by 0 to 180°. As the operation of the comparator is required to be independent of the magnitude of  $A$  and  $B$ , these two quantities are squared using high-gain low-offset amplifiers before being supplied to the comparator.

To understand the operation of the comparator, the input square waves may be regarded as logic variables. At any instant of time, signal  $A$  can be either high or low, that is, either  $A$  or  $\bar{A}$ ; similarly signal  $B$  can be either  $B$  or  $\bar{B}$ . There are four combinations of states,  $A.B$ ,  $A.\bar{B}$ ,  $\bar{A}.B$  and  $\bar{A}.\bar{B}$ . If both signals have a unity mark-space ratio, with equal periods but differing phases, then the four states will occur in a cyclic manner. There are only two possible sequences of these states, as shown in Figure 7.13.

These are:

i. If  $A$  leads  $B$ :  $A.B, \bar{A}.\bar{B}, \bar{A}.B, A.\bar{B}, A.B$ ,

ii. If  $A$  lags  $B$ :  $A.B, A.\bar{B}, \bar{A}.\bar{B}, \bar{A}.B, A.B$ .

From these the following logical statements can be deduced.

- If  $A$  leads  $B$ , when  $A$  changes it gains the opposite polarity to that of  $B$ , while when  $B$  changes it gains the same polarity as that of  $A$ .
- If  $A$  lags  $B$ , when  $A$  changes it gains the same polarity as that of  $B$ , while when  $B$  changes it gains the opposite polarity to that of  $A$ .

The comparator has a logic circuit which examines the input signals at each polarity change to see which of the two statements is true, and so determines whether the sequence is progressing in a tripping or a restraining direction.

There is obviously no certainty that a single change of state indicating a trip sequence represents a real fault condition on the transmission line. This is because of the possibility that the single change of state could be caused by 'noise', or spurious signals, superimposed on one of the main signals. However, greater security of operation is obtained if the criterion for tripping is to receive a number of successive changes each of which indicates a tripping sequence. The comparator therefore has a counter for determining whether one, two, three or four such changes have been observed. Each change in a trip sequence adds to the total count (up to a maximum of four) and each change in a restrain sequence subtracts from the total count (down to a minimum of zero).

Figure 7.14 shows that the counter overcomes the difficulty, commonly associated with other sequence comparators, of interference causing multiple zero crossings, one adding to the total count and the other subtracting. After the pair of crossings the counter is in the same position as before, so that the comparator has inherent rejection of noise.

Additional safeguards are necessary, however, to achieve absolute security against maloperation due to noise. The most critical conditions are when the signal inputs are close to the threshold of operation, or when one or both inputs contain noise of such a large amplitude that extra zero crossings occur separated by a large electrical angle from the true zero crossing of the signal. The following series of operating criteria exemplify the measures which can be applied to obtain security of operation.

a. When the counter is incremented to a count of one, the tripping output is inhibited over a period of 6ms. This feature ensures adequate processing time in the event of power system disturbances causing significant polarizing phase shifts.

b. A tripping output is given by the comparator, subject to (a), after the counter is incremented to two, provided no change of state in a restrain sequence (down-count) is observed after the counter is incremented to one or more. If this condition is not satisfied the limiting condition for tripping is changed to a count of three for an ensuing

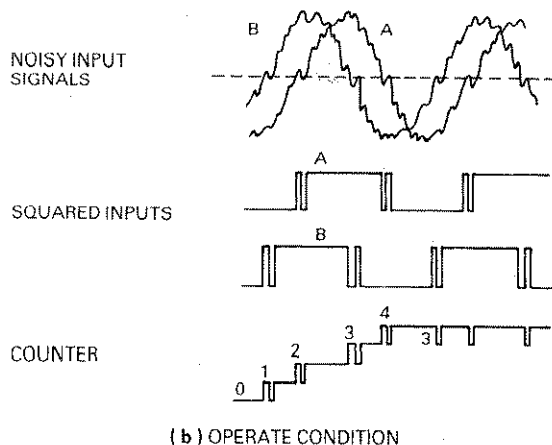
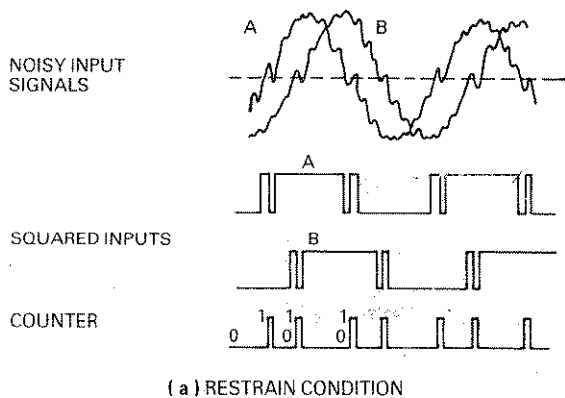


Figure 7.14 Effect of noisy signals on 'Micromho' comparator.

period of 120ms. This safeguard alters the operate criteria of the comparator according to the degree of contamination of the input signals.

c. The counter cannot be incremented by a change of state in a tripping sequence (an up-count) until a timing period of 4ms has elapsed from the last up-count. Each down-count decrements the counter, and terminates any current timing period. These restrictions eliminate maloperation on high-frequency interference, and prevent over-reach due to an exponential component in an input signal, as illustrated in Figure 7.15.

d. A blocking input is provided such that, when it is energized, it will block tripping for counts of less than four. This feature is used where, for example, there is a conflict of information between directional elements and zone one comparators and ensures directionality in the presence of CVT transients.

e. Once the comparator gives a tripping output the output can only reset when the counter is decremented to zero. This prevents wrong resetting of the comparator due to noise superimposed on the input signals.

The effect of (b) and (c) is to allow fast tripping only when the input signals are relatively free of noise and transient components. When the inputs are laden with such components, the processing time is inherently extended to ensure correct comparator response. The minimum comparator operating time is 6ms, and with a suitable integral tripping relay, the overall minimum operating time of the distance scheme is 7ms.

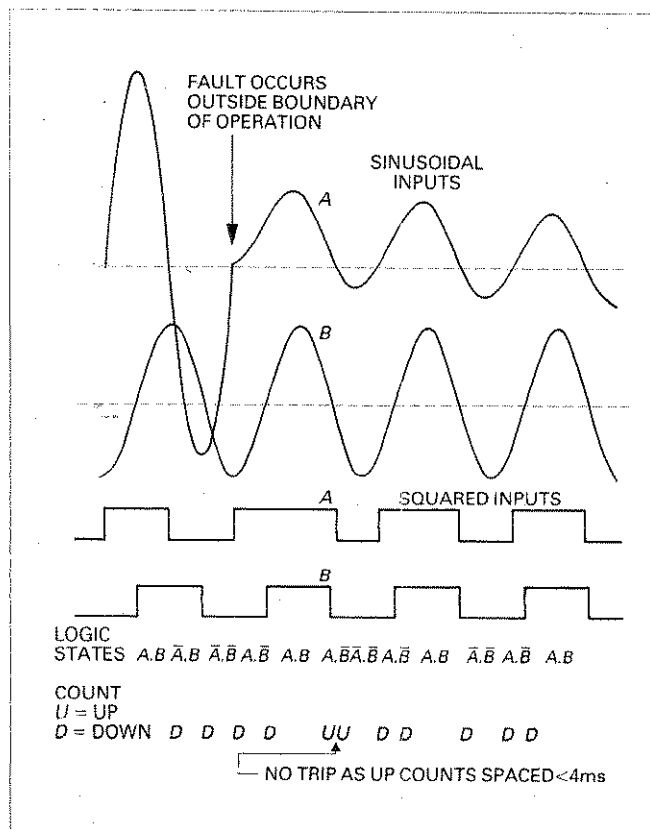


Figure 7.15 Effect of exponential offset on 'Micromho' comparator.

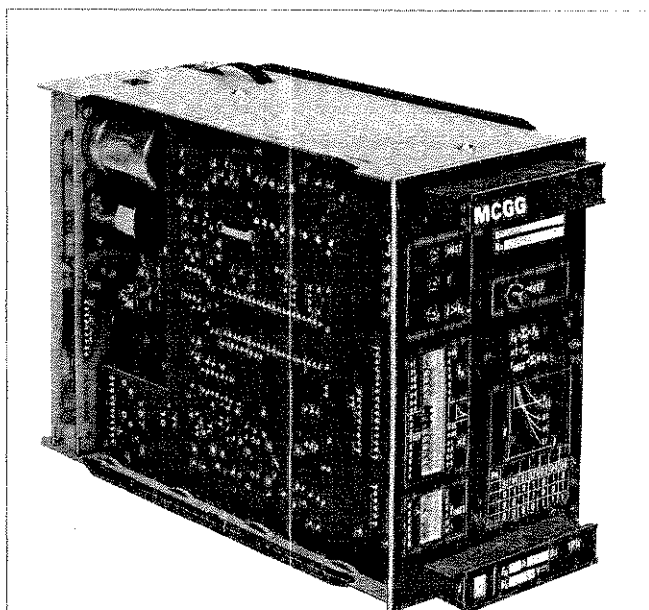
### 7.3.2 Microprocessors

Microprocessors are extremely attractive for use in protection schemes to replace hard-wired contact logic, particularly where a large number of variations in the logic are required such as in the distance relaying scheme shown in Figure 7.11. The hardware comprising input and output interfaces, central processing unit, memory and power supply can be standard and designed and type tested to meet all environmental requirements. A new scheme can then be programmed into this standard hardware using a program held on a separate EPROM chip. Often several schemes can be held in one relay and different schemes selected by the customer by means of a thumbwheel switch. As the program runs continuously, schemes of this type can be largely self-monitoring and arranged to give an alarm should the program cease to run correctly.

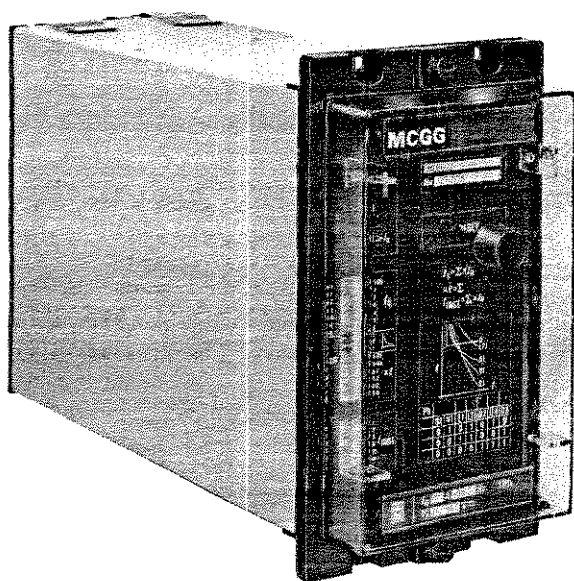
Although analogue to digital converters can be used with microprocessors to perform analogue measurements, the speed of processing can introduce problems with high speed relays. Recently, simple microcomputers have been developed with simple analogue to digital converters on the chip and a small on-chip memory which is mask programmed to a customer's unique requirement by the processor manufacturer. This requires relatively large production runs of relays but is useful for time-delayed overcurrent relays where very high operating speed is not required and a number of time/overcurrent characteristics can be programmed on to the interconnection mask.

The MCGG22 overcurrent relay shown in Figure 7.16 uses a mask programmed microcomputer in this manner. A block diagram of this relay is shown in Figure 7.17. In this device the circuitry is made relatively straightforward by the use of a single chip microcomputer.

The input circuit comprises an interposing current transformer in the relay, the output of which is full wave rectified. The output is fed into a group of current setting resistors, selected by five settings switches. The voltage output from the current setting resistors is used as a signal



(a) RELAY WITHDRAWN FROM ITS CASE



(b) SINGLE PHASE RELAY COMPLETE

Figure 7.16 Microprocessor based overcurrent relay in the 'MIDOS' range.

for the microcomputer and at the setting current, the voltage is the same for all current settings.

The signal processing circuit comprises an eight bit microcomputer which (1) converts the incoming signal into a digital count, (2) accepts inputs from the time curve switches, the time multiplier setting switches and the instantaneous current setting switches, (3) processes the input signals and initiates tripping when the desired operating time and instantaneous current level are exceeded.

The final output is provided by attracted armature elements and relay operation is indicated by light emitting diodes (LED's), one for the time delayed output and one for the instantaneous output from the microcomputer. Each relay is fitted with one changeover contact and one normally open contact. These relays are controlled by the microcomputer outputs buffered by transistors.

### 7.3.3

#### Indication or flagging

In electromechanical relays the operation indicator has usually been a mechanical device associated with the closure of the tripping contact. If attracted armature elements are used as output devices for static relays a mechanical indicator of this type can conveniently be used.

Reed relays or thyristor outputs on the other hand cannot directly provide mechanical flag indication.

For many static relays light emitting diodes (LED's) give a compact means of indication. LED's are low voltage, reliable, solid state light sources having an extended life. Memory for the indication can be provided by either solid state, or latching reed relay, bistable circuits. Latching reed relays have the advantage that the memory is 'non-volatile', that is, it is retained in the event of loss of the d.c. supply.

Solid state circuits can be provided with power-o.f. retention of flagging information either by the use of some form of charge storage device or by using electrically erasable/programmable read-only memory (EEPROM). For many applications, however, the additional cost of providing power-off memory retention may well outweigh its advantages.

### 7.4

#### Electronic relays and electronic trip units

Electronic circuits must not in general interface directly to outgoing terminals because of the transient interference voltages liable to appear on external wiring. Suitably protected opto-coupling devices can be used for low level logic inputs, but where isolated switches are required attracted armature relays or reed relays are normally used.

For high speed circuit breaker trip initiation, attracted armature relays are too slow and the contacts of most reed relays do not have a high enough power rating. A high power, dry reed relay and a mercury wetted reed relay have proved capable of making and carrying 3000 watts for 10,000 operations, but mounting precautions have to be taken to prevent the relays from being affected by mechanical shocks. Thyristor circuits fulfill all requirements and can provide isolated output circuits. In the circuit shown in Figure 7.18 the triggering signal is fed via an opto-isolator to fire thyristor TH1. As circuit breaker tripping coils can have an inductive time constant of over 30ms, TH2 is not triggered until the current is above its holding current. The gate signal delay is provided by TH1, zener diode  $V_z$  and resistor R1.  $V_z$  cannot conduct and fire TH2 until the voltage across R1 exceeds the zener voltage, which is selected so as to exceed the voltage level corresponding to the minimum holding current of TH2.

Finally, it is necessary to add suitable transient protection features to the basic circuitry, to ensure that the overall device is not so sensitive that it cannot withstand the internationally accepted impulse and interference, or 'burst', tests.

Such transient protection features typically increase the operation time of the device by approximately 0.7ms.

### 7.5

#### Advantages of static relays

In recent years the development of compact relay designs has been made possible by the use of static devices. In the early days they were housed in conventional relay cases designed to accommodate electromechanical relays. To obtain the maximum advantage from the application of semiconductors to protective relaying it was necessary to make a fundamental reappraisal of the housing requirements of static relays. The main points to result from this were:

a. The smaller size requirements should allow complete protective schemes to be designed within a composite housing.

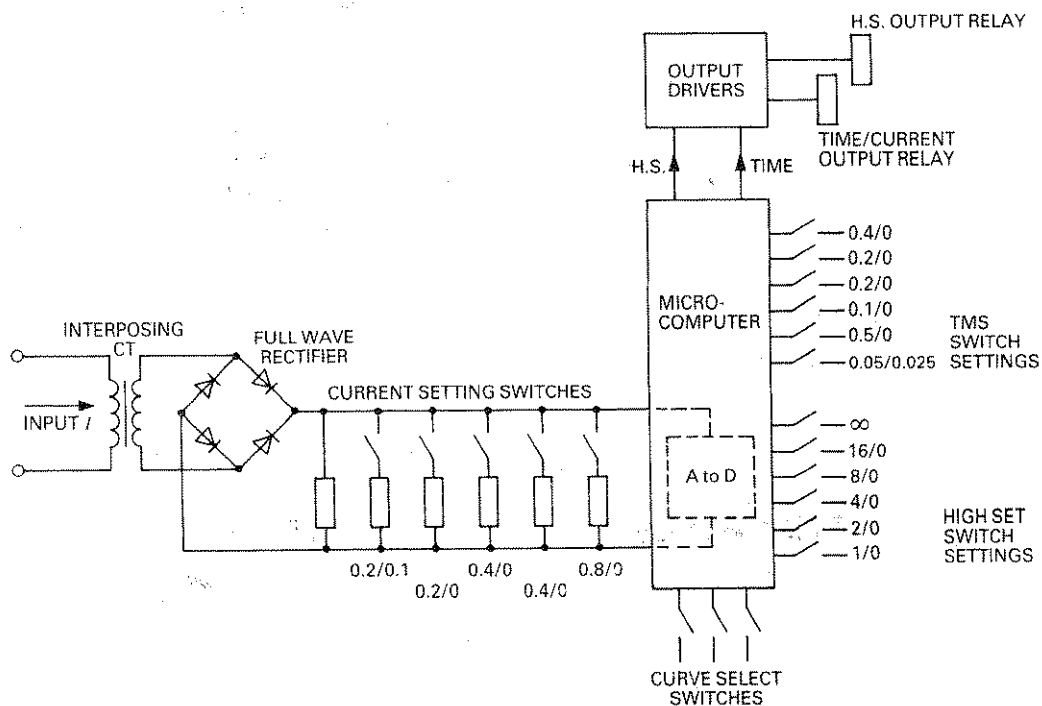


Figure 7.17 Schematic diagram of single phase microcomputer overcurrent relay with high set.

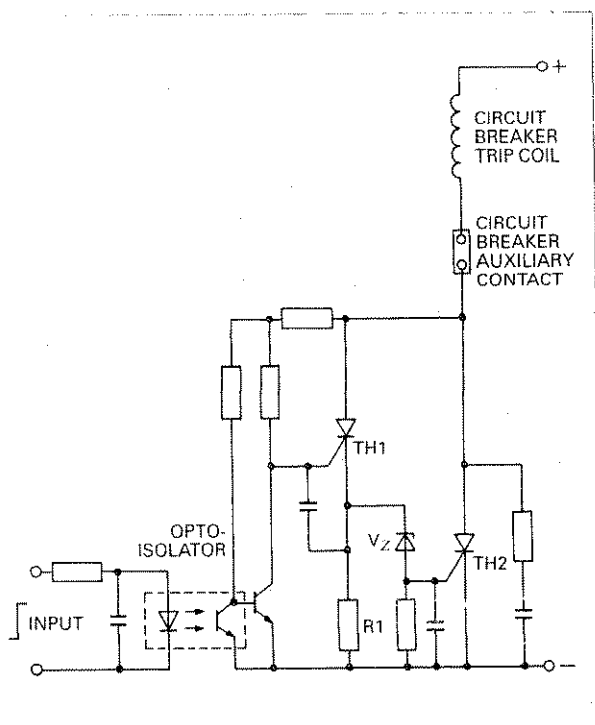


Figure 7.18 Thyristor tripping circuit.

- b. Future protective specifications, written in terms of overall protection schemes, could free designs from the constraints of individual relay elements.
- c. The design should include internal connections between units, to minimize external wiring and so reduce the hazards of surges and interference entering the protection circuitry.
- d. The design should provide access for maintenance and testing.

A modular relay housing system that meets these requirements was designed to accommodate the latest static relays and has now given very effective service for many years. The housing can be mounted in standard 19 in (483mm) racks, which are built as open frame structures either free standing or wall mounted.

If a cubicle arrangement is required, it may be constructed on conventional lines, replacing the solid type front plate with a rack frame-work to which the various units are mounted. A distance protection scheme, illustrated in Figure 7.11, is contained entirely in a single composite modular housing.

Individual modules are plugged into sockets by means of printed circuit board edge connectors, and connections between modules are made using back-plane wiring.

A high current and voltage connector is provided to couple the relay scheme to the various CT and VT connections associated with it. This facilitates the insertion of a split test plug when it is necessary to monitor the various currents and voltages supplied to the relay. A sliding bar is fitted horizontally at the front of the frame to retain individual modules by means of suitably positioned pins. This bar is interlocked with the bridging connector of the plug, so that modules cannot be removed until the bridging connector has been taken out, so isolating the trip circuits and short-circuiting the input connections from the CT secondary circuits.

Light current monitoring and test points can be brought out to the front plate of an individual module, enabling the functioning of particular circuitry to be checked quickly. This examination and checking can be performed by plugging in one or more interposing extender cards, as necessary, so bringing the module out of its case for complete access while still retaining all its connections.

Servicing and repair are made easier by the fact that individual modules can be replaced quickly, so that the equipment can be put back into service immediately.

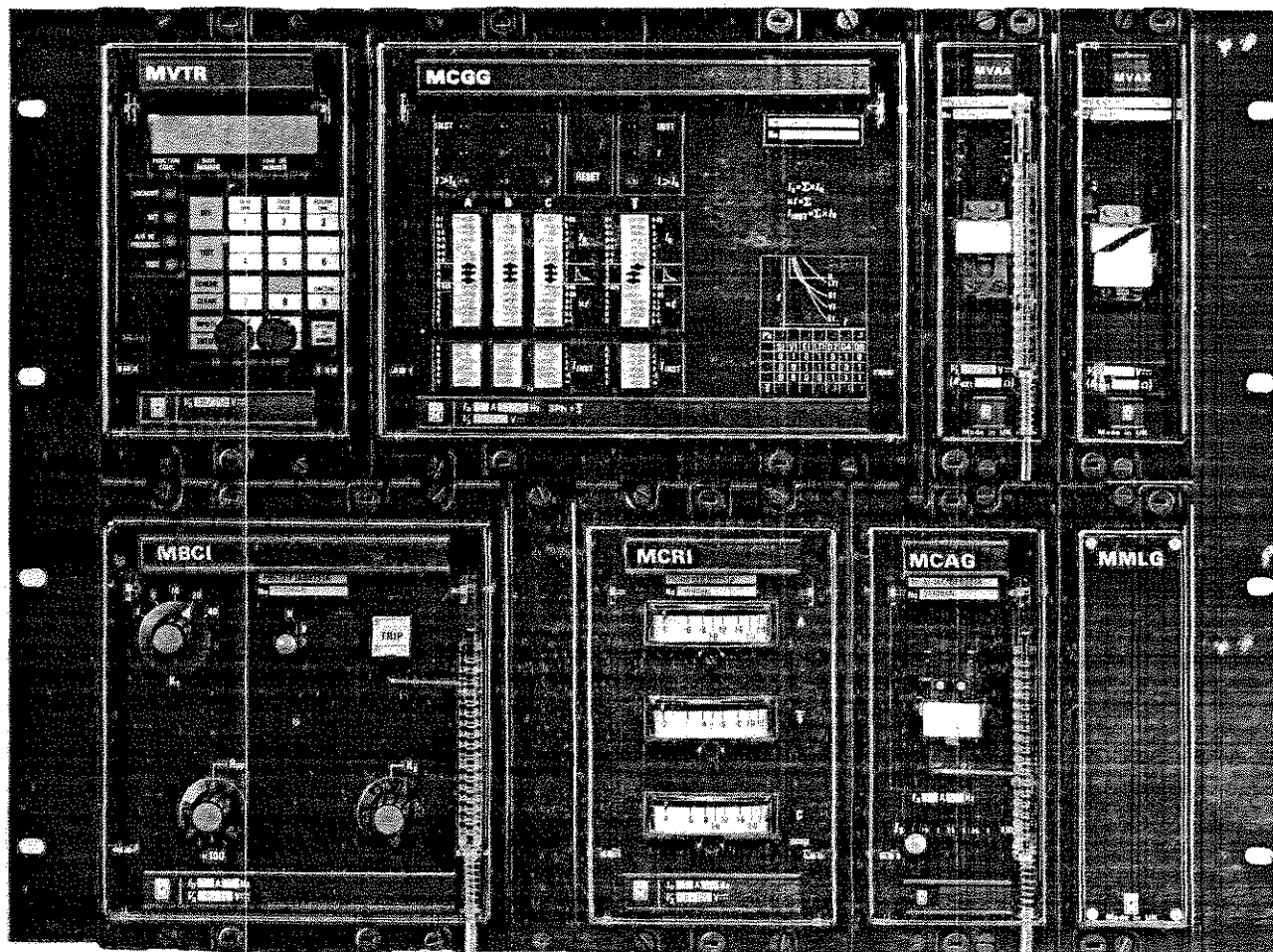


Figure 7.19 Composite assembly of protective relays and associated equipment in the 'MIDOS' housing system.

In addition to complex schemes interwired internally at electronic levels, there still exists a requirement for discrete, separately housed relays. These have the advantage to the customer of greater flexibility in that the customer can interwire relays to his own schemes, modify the wiring and add relay elements as required.

To offer this flexibility and maintain compatibility with rack mounting schemes, a range of 'building block' relays has been designed. These can either be panel mounted singly or mechanically joined together in groups before being mounted in panels or racks, as shown in Figure 7.19.

Individual 'building blocks' are essentially plug-in relays in metal cases with all inputs and outputs wired to high density terminal blocks. A static voltage regulating control relay in this 'building block' range is shown in Figure 7.20.

A separate test block shown in Figure 7.21 is also available in the range and can be wired into any desired place in the scheme.

As the relays can be mechanically joined as a composite assembly before they are mounted on a rack or in a panel, it is possible to interwire and test the schemes to customers' requirements in the relay manufacturer's works, if required.

## 7.6

### ELECTRICAL INTERFERENCE

Semiconductor circuits are subject to the possibility of both catastrophic failure and maloperation in the presence of electrical noise. In the early 1960's, with discrete transistor designs, more attention was directed to the possibility of catastrophic failure and an impulse voltage withstand

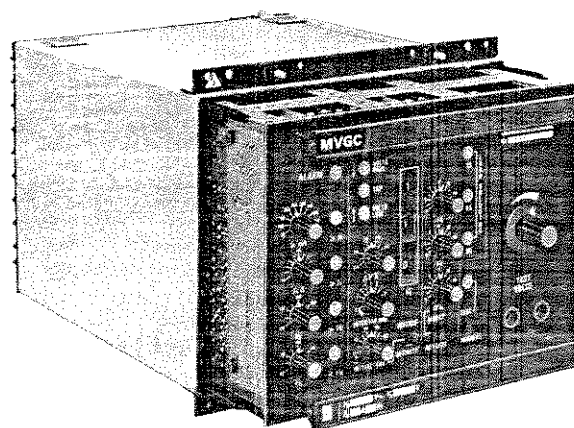


Figure 7.20 Static voltage regulating control relay.

test was specified. This is an impulse waveform having a maximum amplitude of 5kV with a rise time of 1.2 microseconds and a decay time of 50 microseconds to half the peak amplitude. It is applied to the terminals of the relay in the de-energized condition to check that the equipment is not damaged in service. The possibility of maloperation of equipment in the presence of high frequency oscillations

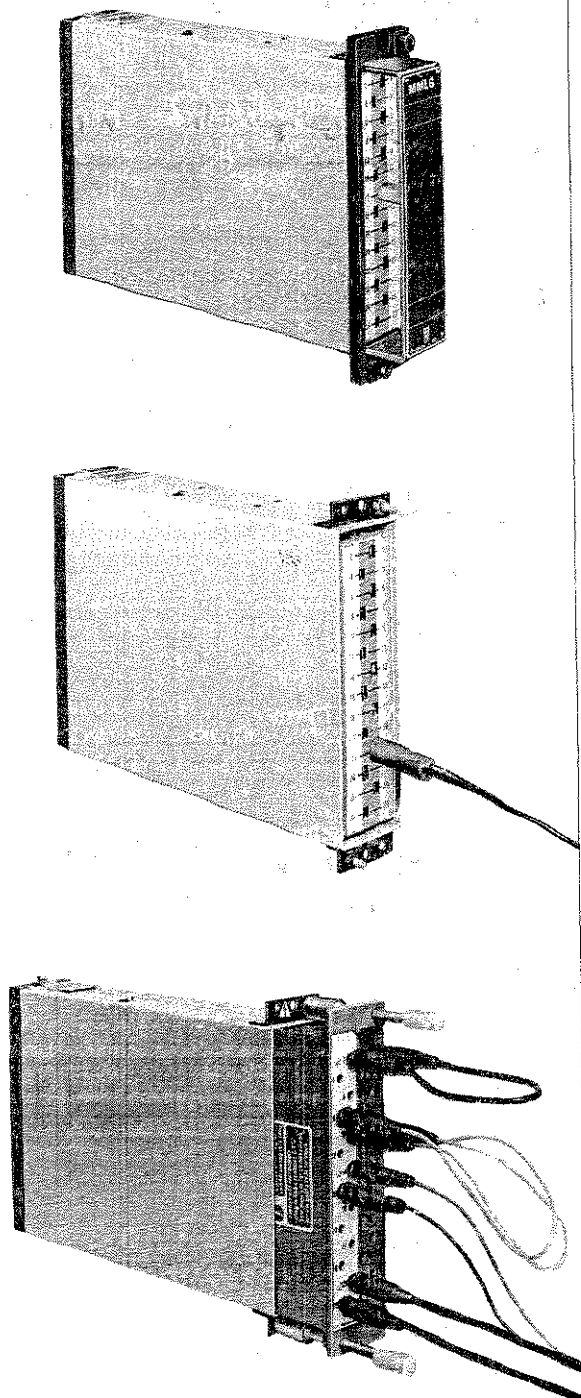
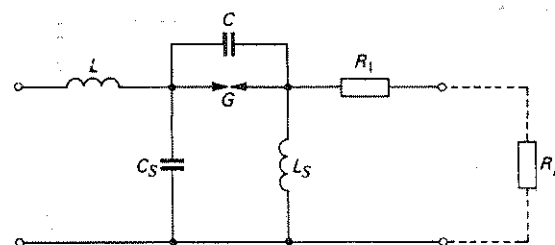


Figure 7.21 Test block of 'MIDOS' range showing use with single and multi-fingered test plugs.

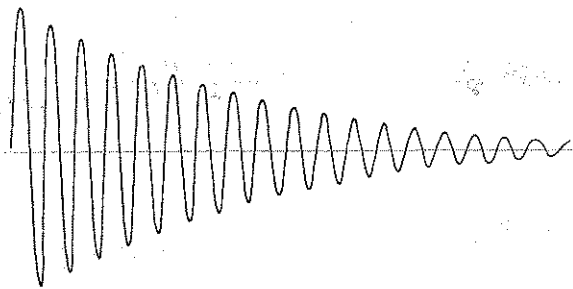
generated by switching operations is covered by a complementary high frequency disturbance test. This test comprises the application of repetitive bursts of high frequency signals representative of those generated during isolator arcing. The waveform, shown in Figure 7.22, is superimposed upon the normal a.c. and d.c. input and output signals, and between circuits, as a common-mode signal. For common mode signals the amplitude of the first peak is 2.5kV and for transverse mode 1kV. The measuring accuracy of the equipment should remain within its claimed limits during the test.

When considering sensitive analogue and high speed digital circuits the problem of hf noise has become the more important consideration. Tests have shown that during isolator switching, earth potentials can rise con-



$L = 26\text{H}$        $G = \text{ARC GAP}$   
 $C = 0.02\mu\text{F}$        $R_1 = 200\Omega$   
 $L_S = 6.3\mu\text{H}$        $R_L = \text{LOAD}$   
 $C_S = 0.004\mu\text{F}$

(a) GENERATOR FOR HF DAMPED OSCILLATIONS



Frequency      1.0MHz  
 Repetition rate      400 bursts per second  
 Decay time to half amplitude      3 to 6 cycles

(b) TYPICAL HF OSCILLATION

Figure 7.22 Oscillation frequency for hf disturbance tests.

siderably due to transient hf currents in the MHz range flowing in the earth mat.

The resultant high transient voltages which appear across the switching station earth mat give rise to common mode voltages between separate circuits of the same equipment, because of the different points of earthing of each circuit. With the IEC test voltage of 2.5kV at 1MHz, an interwiring capacitance of 1 pF will cause a current of 15mA to flow between circuits. This cannot be allowed to flow through sensitive MOS digital logic circuits as certain maloperation would result. The design philosophy followed is to contain sensitive high speed circuitry within an equipotential, electrically 'quiet' area and to exclude common mode currents.

In this technique, shown in Figure 7.23, all inputs are isolated and where primary/secondary capacitance is high, a screen is introduced to deflect common mode currents to earth.

Other tests, a radio frequency test and an electrostatic discharge (ESD) test, are being considered by the IEC and leading protection manufacturers but standards have not yet been agreed.

In common with all modern solid state equipment GEC ALSTHOM Measurements' relays contain devices which may be damaged by accidental electrostatic discharges.

The modules of these relays are completely safe when housed in the relay case and should not be withdrawn unnecessarily. Each module incorporates the highest level of practical protection for its semi-conductive devices, but any work on the electronic circuitry is carried out in a special handling area such as is described in BS5783. The main characteristics of this area are that the operators, the bench and all handling facilities and tools are grounded, via safety resistors, by the use of suitable conducting materials. This



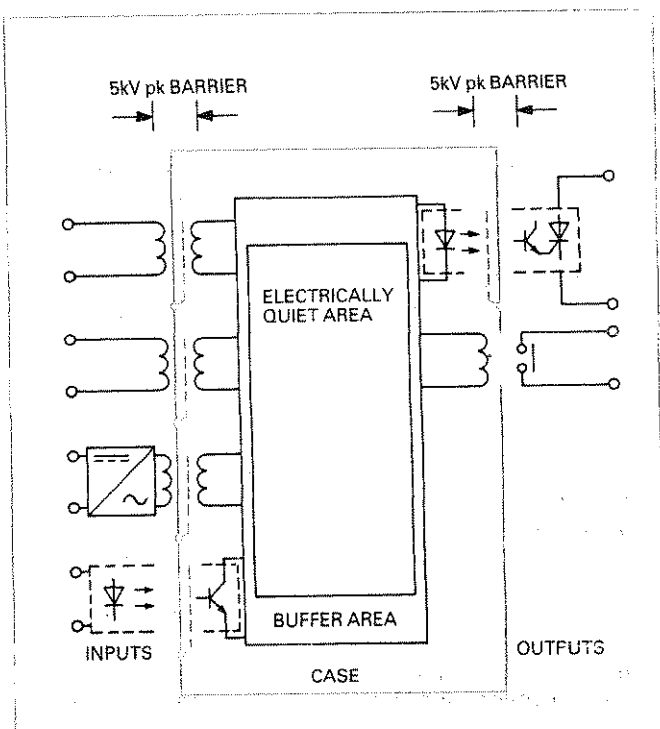


Figure 7.23 Provision of electrically quiet area.

prevents the build up of electrostatic charge and any charge on an operator is dissipated safely to ground without damage to equipment. During storage or transport the modules are contained in static shielding bags.

These precautions ensure the high reliability and long life for which the relay has been designed and manufactured.

## 7.7

### QUALITY CONTROL AND PRODUCTION TESTING

With static relays the manufacture of components, previously under the control of the relay manufacturer in respect of electromechanical designs, is largely in the hands of specialist electronic component manufacturers. This means that to ensure the requisite, high reliability the relay manufacturer must undertake extensive quality control tests on electronic components before they are used. With the rapid advance of semiconductor technology and the widespread acceptance of static relays, the problems of the design, manufacture and testing of these relays necessitated increased attention.

The use of integrated circuits, firstly linear operational amplifiers, then digital gates and logic, followed by large scale digital integrated circuits, memories and microprocessors, accentuated the problems of quality control of components and production test methods of complex electronic assemblies.

As the volume and complexity of static relays outgrew the early production quality control and testing methods, automatic programmable test equipment was introduced to ensure effective production methods.

Production testing and quality control techniques have two main objectives:

- i. To maximize in-service reliability.
- ii. To minimize production costs.

To minimize production costs it might be supposed that the best procedure would be to test only the complete equipment. This would be so if every equipment passed its test, but failing this there would be the problems of diagnosing and rectifying some inevitable failures in extremely complex equipment. Further, failure of one component or one assembly error may cause consequential failure of

other components or assemblies, so magnifying the cost of failures and complicating the task of diagnosing the failure. It is generally held that the cost of rectifying a failure increases by a factor of ten for every stage of assembly.

A philosophy of testing at each production stage is therefore followed. Although repeated testing will increase the reliability of the product it is necessary to build in additional procedures to eliminate early life failures. These are usually in the form of 'burn-in' or heat soak tests. Parameters of the components are examined for drift which is taken as an indication of possible early life failure even though the devices may not have actually failed at the conclusion of the test.

Automatic test procedures have become essential with increasing production volume, variety and the technical complexity of equipment. Equipments are designed so that printed circuit boards and modules are complete functional entities in order that they can be tested and faults diagnosed at each stage. This is done by means of software tests and diagnostic routines. Calibration takes place at the module test stage, followed by a heat soak at 70°C and then a recheck of the calibration. The module is then suitable for inclusion in schemes or for dispatch to a customer as a spare. Cases and case wiring are independently checked, so that possibility of failure at the scheme test stage is low. This system of testing is shown in the flow diagram in Figure 7.24.

## 7.7.1

### Components

Inspection and parametric tests of components as they are received from suppliers can eliminate early life failures. In analogue devices such as transistors and operational amplifiers, devices are burnt-in at an elevated temperature and for some applications critical parameters are monitored during burn-in.

Parameters are rechecked after burn-in and devices exhibiting drift of certain parameters are rejected as possible early life failures. A drift limit of up to 10% is generally used, but for checks of leakage current during voltage blocking tests a drift of up to 100% is usually acceptable.

Devices are loaded 200 at a time into jigs and are tested by a programmable tester which identifies the location of rejects and prints out parameters which are out of limits.

Digital circuits are burnt-in either dynamically at 70°C or statically at 85°C for 160 hours, with parametric tests before and after the burn-in phase. An example of the testing of memories and microprocessors is the EPROM and processor used in distance relays. A memory bit check is performed on EPROM's using two chequer board patterns with a heatsoak for 72 hours at 100°C between each pattern. A test program is then loaded into an EPROM and verified by the PROM programmer. This is used in conjunction with the microprocessor under test to perform:

- a. A functional test of the microprocessor, for example the instruction set.
- b. A dynamic burn-in for 48 hours at 70°C using most of the instruction set. A successful running signal is given by causing one output to oscillate at approximately 1 Hz.
- c. The functional test is then performed again.

The individual devices are checked by substitution—a known good processor against an unknown EPROM and vice versa.

## 7.7.2

### Printed circuit boards

Static relays incorporate a wide range of component technologies from analogue to VLSI devices sometimes even on the same p.c.b. Production test equipment must be able to cater for all of these devices. Assembled printed circuit boards are tested for correct assembly using test equip-

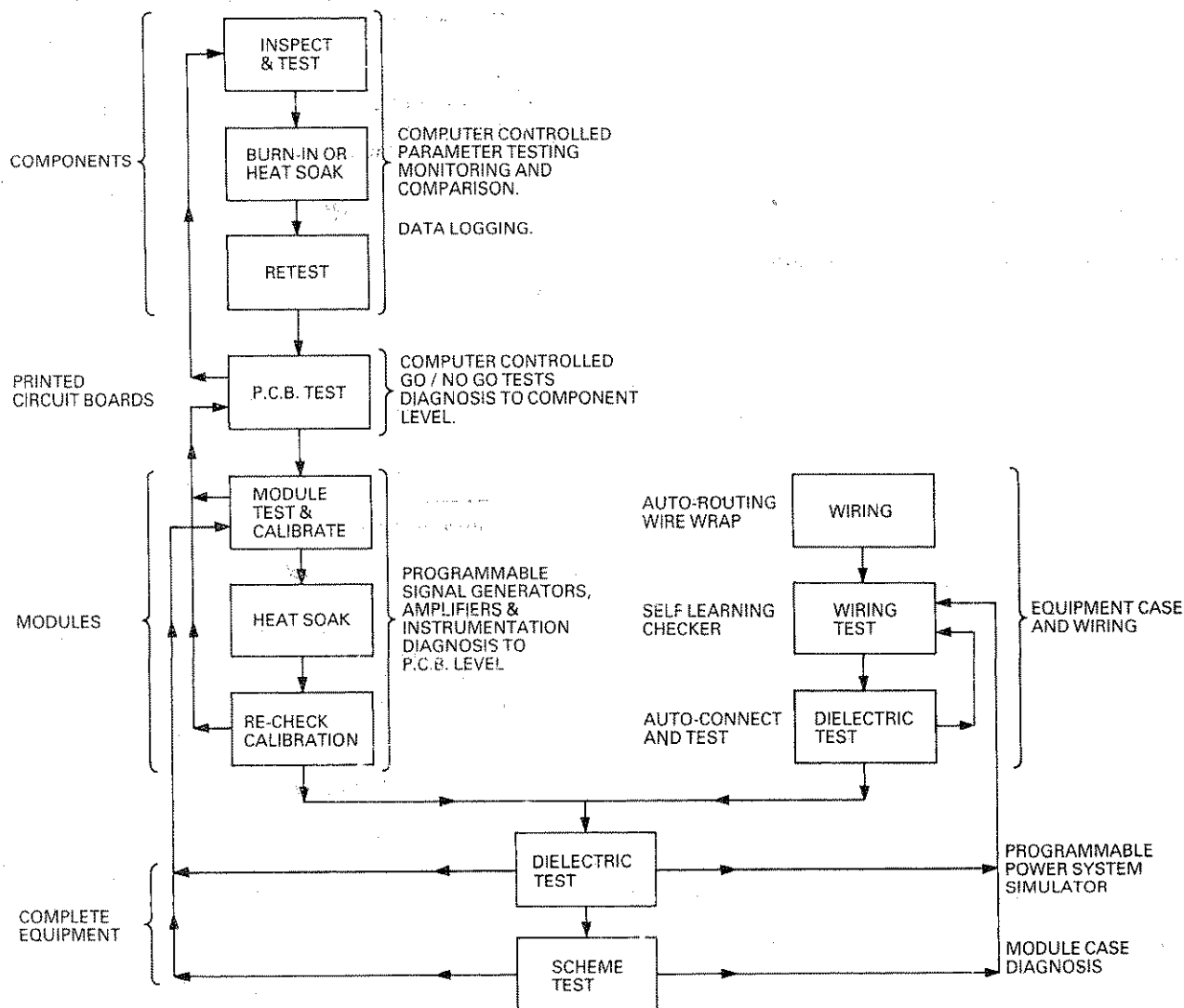


Figure 7.24 Summary of production tests.

ment, as shown in Figure 7.25, which provides for the complete in-circuit testing of analogue, digital and hybrid p.c.bs. With a high testing speed the equipment rapidly detects any p.c.b. assembly defects such as solder 'bridges', dry joints, or circuit discontinuity, as well as testing all passive and active components. Access to each circuit node of the board under test is made via a special 'bed of nails' interface jig.

In-circuit testing gives a powerful diagnosis of production faults down to component level, but as electronic circuits become faster, more powerful and more complex, the need to test each p.c.b. functionally also increases. In-circuit testing is used to 'screen out' assembly faults so as to allow the functional testers to be devoted to identifying operational faults, a task to which they are more suited. Modern functional testers have a wide range of computer controlled analogue and digital stimulus and measurement units, which together with sophisticated software packages for test program generation and fault simulation provide a powerful tool to exercise the unit under test. With the aid of computer guided probes p.c.b. faults can be located quickly and more accurately by the test technician without the need for constant reference to circuit diagrams. Functional testing gives the assurance that the p.c.b. under test actually operates according to specification when powered up and exercised over its full operating range.



Figure 7.25 Automatic testing of printed circuit boards.

### 7.7.3 Modules

Assembled modules are tested and calibrated on a programmable system comprising multiphase a.c. signal generators, power supplies, digital voltmeters, timer-



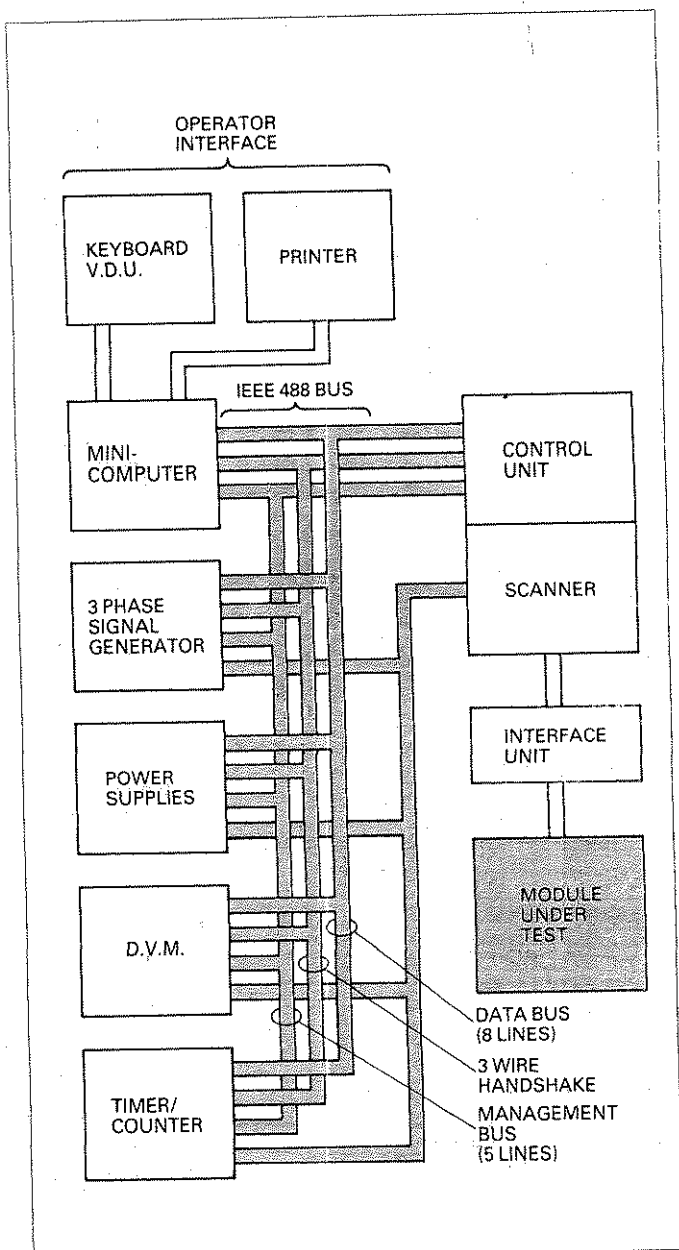


Figure 7.26 Computer controlled module test and calibration.

counters and scanning equipment connected to a minicomputer through an IEEE 488 bus system as shown in Figure 7.26. This enables a module test program on floppy disk to control signals to, and measurements on, the module. Instructions are received and issued to the tester through a visual display unit/keyboard for switch position changes, calibration adjustments and so on. The alternative selectable schemes and timing routines programmed into distance relays are, for example, exhaustively tested at this stage.

#### 7.7.4

##### Cases and case wiring

Back-plane wiring between edge connector sockets and outgoing terminals is connected by means of a wire wrapping technique. The wire wrapping tool is automatically aligned on to the correct terminal by means of an X-Y locator programmed by paper tape. When the case and wiring is completely assembled the wiring is checked by a back-plane wiring checker. This equipment 'learns' the wiring details from a known good case and stores the test program on a magnetic cartridge. On the wiring under test, test connections are made to all edge connector sockets and terminals and any errors will be printed out by the test equipment.

#### 7.7.5

##### Insulation testing

Normally all equipments are subjected to routine insulation testing at 2.5kV r.m.s. It is important that the case wiring is checked before insertion of the modules. The simplest test equipment is programmed by hard-wired switches, but this limits its application and flexibility. Alternatively this feature can be software-programmed to provide a more adaptable arrangement in which a reed scanner interface unit, with a 5kV withstand capability, accesses every possible terminal position.

#### 7.7.6

##### Final test

Several techniques and equipments are required to test each type of fully assembled relay to specification. These are described in more detail later in Section 23.3 Production Testing.

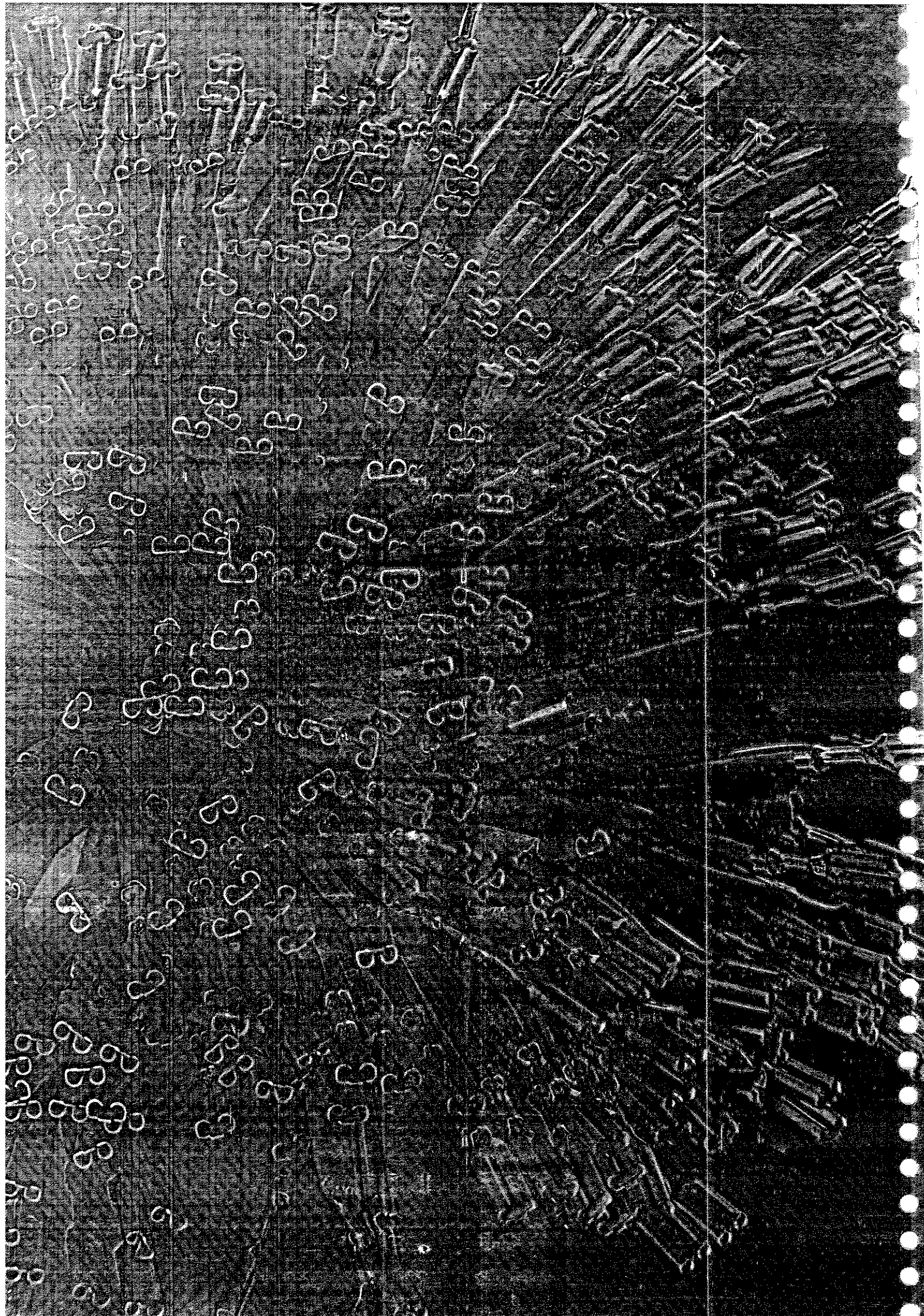
#### 7.8

##### FUTURE TRENDS

The future of electronic relaying can be seen as taking two distinct directions—complex high performance digital or microcomputer based integrated protections, and a range of single function discrete relays duplicating to some extent the functions of the integrated protections.

The discrete relays with individual current and voltage inputs and contact outputs will enable simple protection requirements to be met economically. They will also ensure maximum flexibility to enable customers to design and modify medium sized schemes using these relays as 'building blocks' in an interwired rack or panel mounted scheme.

The use of digital and microcomputer techniques will increase, not only for control and data collection functions, but also for the measurement functions associated with protection. For overall protection, control and data collection schemes it is envisaged that some form of multi-processor system with a common data base will be developed. For the protection part of such a system the established principle of segregation of protections should be maintained. The processors used for the protection function should be completely independent and interfaced to the rest of the system in such a way that for failures in other parts of the system the protection would 'stand alone'.



# Protection signalling

8

- 8.1 Introduction.
- 8.2 Application of protection signalling.
- 8.3 Performance requirements.
- 8.4 Transmission media, interference and noise.
- 8.5 Methods of signalling.
- 8.6 Practical signalling systems.

## 8.1 INTRODUCTION

In order to achieve fast clearance and correct discrimination for faults anywhere within a high voltage power network, it is necessary to signal between the points at which protection relays are connected.

The communication links available for protection signalling are:

- i. Private pilot wires or channels installed by the power authority.
- ii. Pilot wires or channels rented from a national communication authority.
- iii. Carrier channels at high frequencies over the power lines.
- iv. Radio channels at very high or ultra high frequencies.
- v. Optical fibres.

Whether or not a particular link is used depends on factors such as the availability of a national communication network, the distance between protection relaying points, the terrain over which the power network is constructed, as well as cost. These matters will be discussed at greater length later in the chapter.

## 8.2 APPLICATION OF PROTECTION SIGNALLING

Protection signalling is used to implement unit protection schemes or provide teleprotection commands.

### 8.2.1 Unit protection schemes

Phase comparison and current differential schemes use signalling to convey information concerning the relaying quantity—phase angle of current and phase and magnitude of current respectively—from a remote relaying point to a local relaying point. Comparison of local and remote signals provides the basis for both fault detection and discrimination of the schemes.

Operation of the schemes and the requirements of their associated signalling channels are described in Chapter 10.

### 8.2.2 Teleprotection commands

The carrier aided distance schemes described in Chapter 12

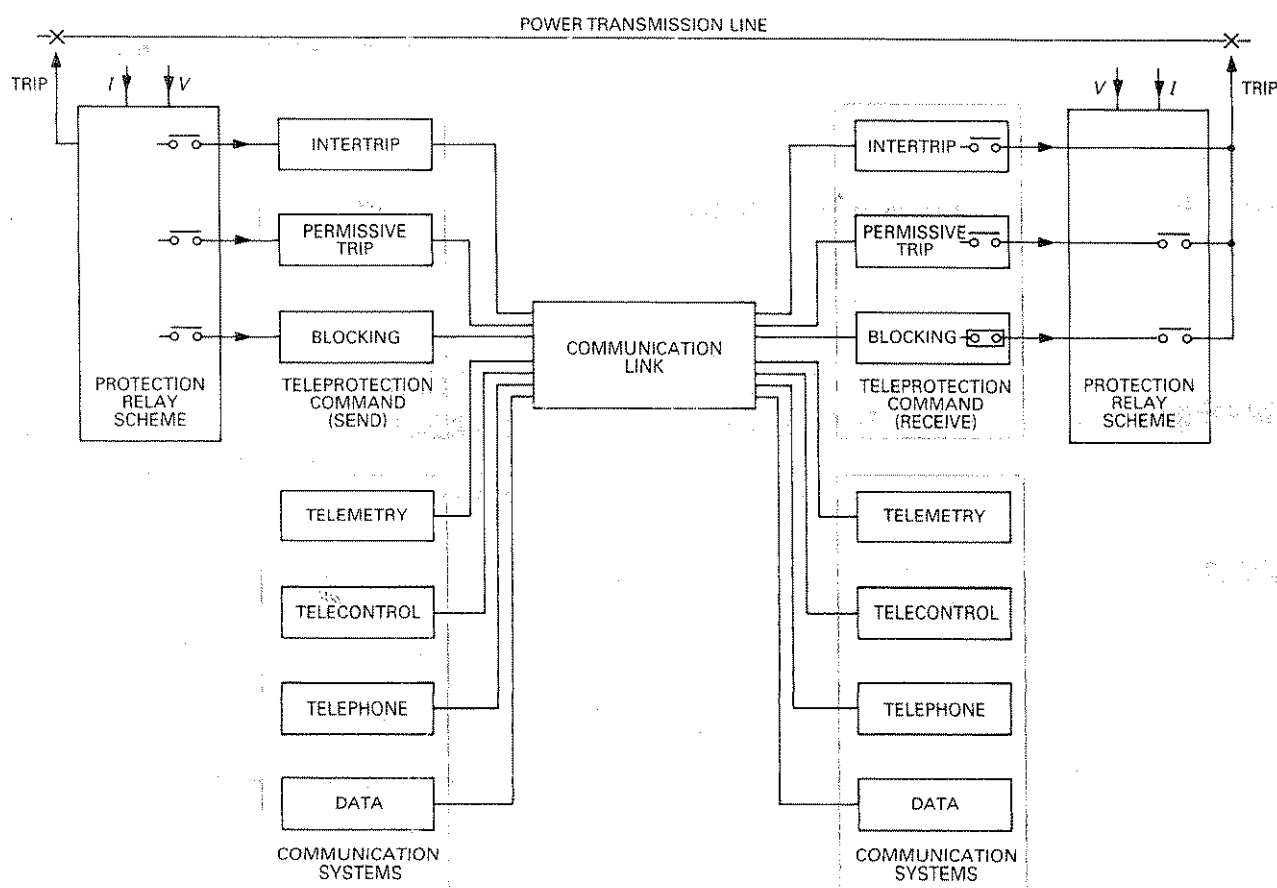


Figure 8.1 Application of protection signalling and its relationship to other systems using communication. (Shown as a unidirectional system for simplicity).

or directional comparison schemes use signalling to convey a single command, usually in the form of a contact closure, from a remote relaying point to a local relaying point, where the additional information is used to aid or speed up clearance of faults within a protected zone or to prevent tripping for faults outside a protected zone.

Intertripping schemes, described in Chapter 18, use signalling to convey a trip command to remote circuit breakers to isolate circuits by 'sympathetic' tripping. For high reliability EHV protection schemes, intertripping may be used to give back-up to main protections, or back-tripping in the case of breaker failure.

Control functions such as the automatic reclosure of remote circuit breakers require an appropriate teleprotection command.

Teleprotection systems are often referred to by their mode of operation, or the role of the teleprotection command in the system.

### Intertripping

In intertrip (direct or transfer trip) applications, the command is unmonitored by a protective relay at the receiving end. Reception of the command causes circuit breaker operation.

### Permissive tripping

Permissive trip commands are always monitored by a protection relay. The circuit breaker can be operated only when reception of the command coincides with operation of the protective relay responding to a system fault.

### Blocking

Blocking commands are always monitored by a protection relay. The circuit breaker can be operated only if the command is absent when the protective relay is operated by a fault.

Figure 8.1 shows the typical applications of protection signalling and their relationship to other signalling systems commonly required for the efficient control and management of a power system.

### 8.3

Overall fault clearance time is made up of the signalling time and the protection relay, trip relay and circuit breaker operating times. This total time must be less than the maximum time for which a fault can remain on the system for minimum plant damage, loss of stability and so on. Fast operation is therefore a pre-requisite of most signalling systems.

Typically the time allowed for the transfer of a command is of the same order as the operating time of the associated protection relays. For protection of the EHV transmission system in the United Kingdom, nominal allowances range from 15 to 40ms dependent on the mode of operation of the teleprotection system.

Protection signals are subjected to the noise and interference associated with each communication medium. If noise reproduces the signal used to convey the command, unwanted commands may be produced, whilst if noise occurs when a command signal is being transmitted, the command may be slowed up or missed completely. Perfor-

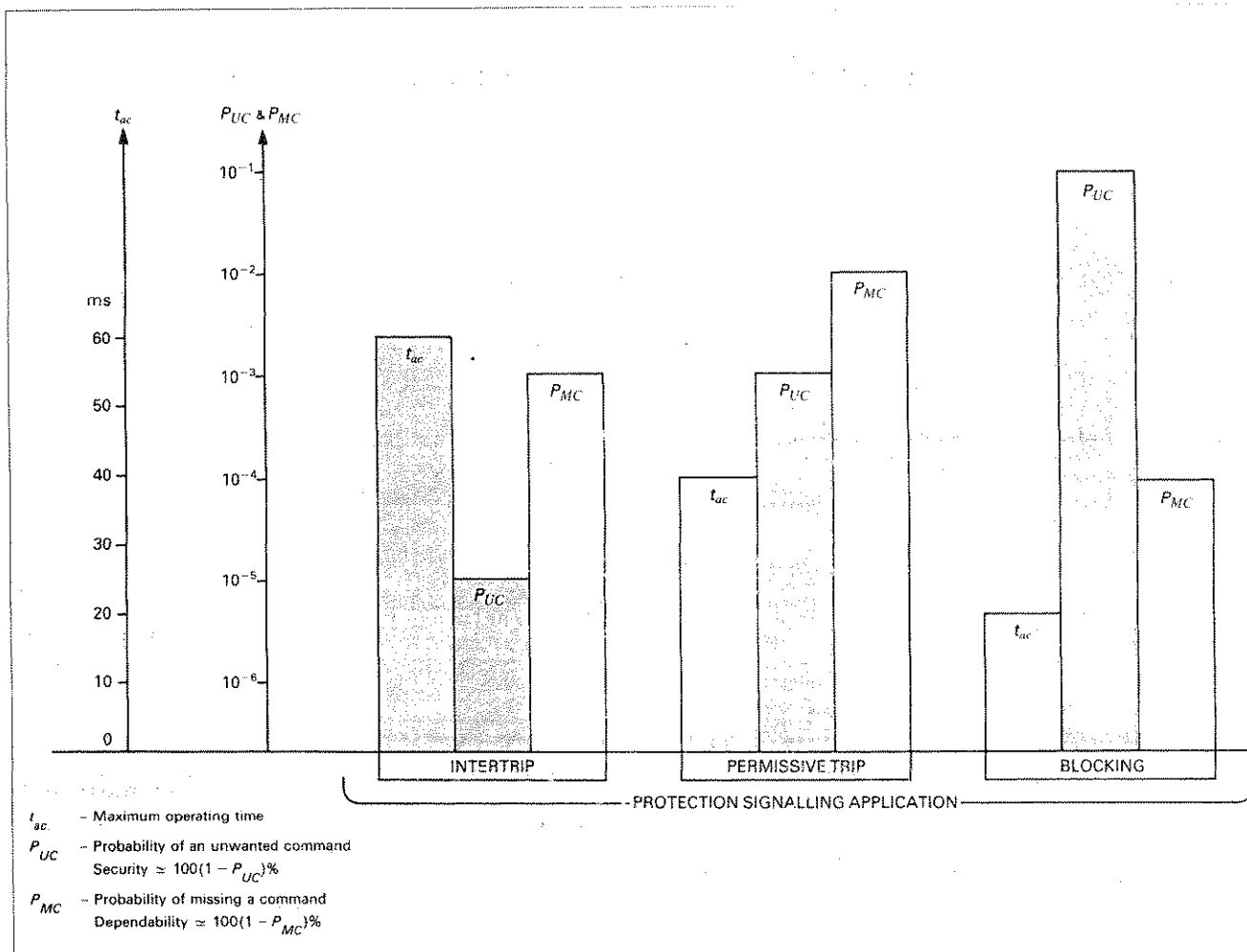


Figure 8.2 Typical performance requirements for protection signalling when the communication link is subjected to noise.

mance is expressed in terms of security which is assessed by the probability of an unwanted command occurring, and dependability, which is assessed by the probability of missing a command. The required degree of security and dependability is related to the mode of operation, the characteristics of the communication medium and the operating standards of the particular power authority.

Typical design objectives for teleprotection systems are not more than one incorrect trip per 500 equipment years and less than one failure to trip in every 1000 attempts, or a delay of more than 50ms should not occur more than once per 10 equipment years. To achieve these objectives special emphasis may be attached to the security and dependability of the teleprotection command for each mode of operation in the system as follows:

#### Intertipping

Since any unwanted command causes incorrect tripping very high security is required at all noise levels up to the maximum which might ever be encountered.

#### Permissive tripping

Security somewhat lower than that required for intertipping is usually satisfactory since incorrect tripping can occur only if an unwanted command happens to coincide with operation of the protection relay for an out-of-zone fault.

For permissive over-reach schemes, resetting after a command should be highly dependable to avoid any chance of maloperations during current reversals.

#### Blocking

Low security is usually adequate since an unwanted command can never cause an incorrect trip. High dependability is required since absence of the command could cause incorrect tripping if the protection relay operates for an out-of-zone fault.

Typical performance requirements are shown in Figure 8.2.

#### 8.4

##### TRANSMISSION MEDIA FOR PROTECTION SIGNALLING

The transmission media which provide the communication links involved in protection signalling are private or rented pilots or channels, power line carrier, radio and optical fibres.

Pilot wires are continuous copper connections between signalling stations, while pilot channels are discontinuous pilot wires with isolation transformers or repeaters along the route between signalling stations.

Power line carrier involves transmission of signals along the power lines.

Radio uses transmitters and receivers with appropriate aerial systems to exploit the ether as the transmission medium.

Optical fibres provide a medium for the transmission of light signals.

General purpose telecommunications equipment operating over power line carrier, radio or optical fibre media incorporate frequency translating or multiplexing techniques to provide the user with standardized commun-

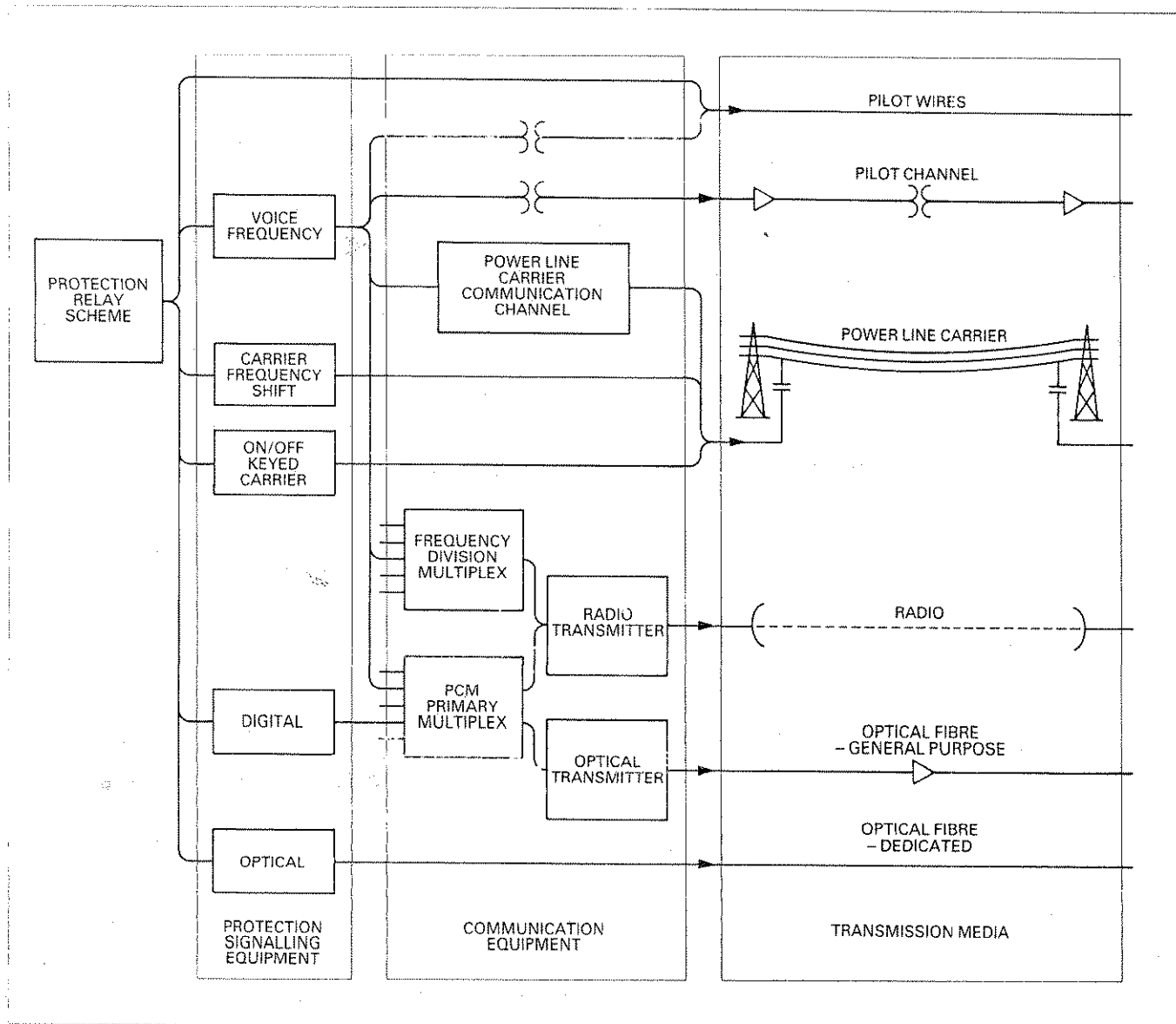


Figure 8.3 Communication arrangements commonly encountered in protection signalling.

ication channels. These are suitable for speech or other applications using frequencies of up to 4kHz nominally and are often referred to as voice frequency (vf) channels. Protection signalling equipments operating at voice frequencies can exploit the standardization of the communication interface so that similar equipment may be used regardless of the medium. Where voice frequency channels are not available or suitable, protection signalling may make use of a medium or specialized equipment dedicated entirely to the signalling requirements.

Figure 8.3 illustrates the communication arrangements commonly encountered in protection signalling.

#### 8.4.1

##### Private pilot wires and channels

Private pilot wires are owned by the power authority and may be laid in a trench with high voltage cables, laid by a separate route or strung as an open wire on a separate wood pole route.

Transverse induced voltages at power frequencies are kept down to a minimum by the selection of pairs to be used for protection signalling but the signalling equipment should be proof against at least 150 volts. These voltages can be limited by the use of gas discharge arresters. An overvoltage relay which puts a short circuit across the pilots has also been used, but problems arise if the overvoltage has

been generated by a fault that the protection signalling is attempting to clear.

Voltages due to rises in the station earth potential at the terminal station can be very high, so terminal isolation transformers are used to reduce the risk of injury to people and damage to equipment on the pilot side. This transformer also acts as a barrier to longitudinal voltages induced in the pilot wires, thus reducing the risks on the station side. These induced voltages can be limited by using transformers at intermediate points along the signalling route.

Voltage impulses due to lightning and transients due to power circuit isolator switching are also hazards that the signalling equipment must withstand without damage. Private pilot wires have been used for protection signalling since 1905, but there has often been concern about their cost and whether their reliability is up to the high standard desired for a service of this kind. Cost is more likely to be a bar to their use than unreliability.

Disruption by linesmen and damage by cranes or diggers are other hazards that a signalling system employing this medium must be proof against.

Signalling can be carried out at a relatively high level (+ 10dBm) on private pilots links, as there is normally no limit placed by national communication authorities. The limit will be imposed by any amplifiers and associated equipment at intermediate points along the route. This



enables a satisfactory signal-to-noise ratio to be achieved over an operating range of about 40dB, giving an acceptable performance. The higher level of transmission may also be used to maintain a useful range for a system operating at frequencies at which the losses in the link are relatively high.

The capacity of a link can be increased if frequency division multiplexing techniques are used to run parallel signalling systems, but some power authorities prefer the link to be used only for protection signalling.

Private pilot wires or channels can be attractive to an authority running a very dense power system with short distances between stations, particularly if it is not possible to rent channels from the national communication authority or if rented channels are considered not to have the high reliability and availability that is required for protection signalling applications.

#### 8.4.2

##### **Rented pilot wires and channels**

These are rented from national communication authorities and, apart from the connection from the relaying point to the nearest telephone exchange, the routing will be through cables forming part of the national communication network.

If the power system operator is thinking of using pilot links for signalling, he must decide whether, on economic grounds, it is better to rent for, say, 25 years, or to lay his own pilot cable, assuming that the national network of the country in question is suitable for protection signalling.

On a vast rented network, such as that in the United Kingdom, the electrical and human interference to which protection signalling systems can be subjected is very considerable.

The chance of voltages being induced in rented pilots is smaller than for private pilots, as the pilot route is normally not related to the route of the power line with which it is associated. However, some degree of security and protection against induced voltages must be built into signalling systems.

Station earth potential rise is still significant and isolation must be provided to protect both the personnel and equipment of the national communication authority.

In the United Kingdom a transformer that will withstand 15kV r.m.s. between the line winding and equipment winding and earth, is connected between the signalling equipment and the pilot link.

Electrical interference from other signalling systems, particularly 17, 25 and 50 Hz ringing tones up to 150V peaks, and from noise generated within the equipment used in the national communications network, is a common hazard.

The signalling system must also be proof against intermittent short and open circuits on the pilot link, incorrect connection of 50 volts d.c. across the pilot link and other similar faults.

The most significant hazard to be withstood by a protection signalling system using this medium arises when a linesman inadvertently connects across the pilot link a low impedance test oscillator that can generate signalling tones. Transmissions by such an oscillator may simulate the operating code or tone sequence which, in the case of direct intertripping schemes, would result in incorrect operation of the circuit breaker.

Communication between relaying points may be over a two-wire or four-wire link. Consequently the effect of a particular human action, for example an incorrect disconnection, may disrupt communication in one direction or both.

It is not only hazards that place limitations on signalling systems. The national communication authority itself imposes stringent requirements upon privately owned equipment connected to its network.

The signals transmitted must be limited in both level and bandwidth to avoid interference with other signalling systems. In the United Kingdom the maximum one minute mean power level permitted is -13dBm for frequencies in the band 200-3200Hz. Consequently, if frequency division multiplexing techniques are used, the output per signalling channel is a function of the number of channels that can be connected in parallel on one pilot link. For example, if five channels can be connected in parallel, the maximum level permitted is -20dBm per channel.

In the United Kingdom pilot wires for operation from d.c. up to 200Hz are usually available for radial distance up to 11km and these may be utilized for pilot wire unit protection schemes operating at 50Hz.

Although maximum signal levels of 50V and 60mA at 50Hz are specified for these circuits, dispensations usually permit higher levels to be used so long as their duration is associated with the fast fault clearance time normally expected from a high reliability protection system. For more general application on a rented circuit, the use of signalling in the speech band (200-3,200Hz) is normally preferred.

With a power system operating at, say, 132kV, where relatively long protection signalling times are acceptable, signalling has been achieved above speech together with metering and control signalling on an established control network. Consequently the protection signalling was achieved at very low cost. High voltage systems (275 and 400kV) have demanded shorter operating times and improved security, which has led to the renting of pilot links exclusively for protection signalling purposes.

#### 8.4.3

##### **Carrier channels at high frequencies over power lines**

For the protection of long line sections, or if the route involves installation difficulties, it is too expensive to provide a pilot link for protection signalling, and other means are sought.

High frequency signal transmission along the actual overhead power line offers advantages over the use of pilot links. It is robust and therefore reliable, constituting a low loss transmission path that is fully controlled by the power authority.

High voltage capacitors are used, along with drainage coils, for the purpose of injecting the signal on to and extracting it from the line.

Injection can be carried out by impressing the carrier signal voltage between one conductor and earth or between any two phase conductors, the two phases being selected for lowest transmission loss; this depends on the overhead line configuration, ground clearance and earth resistivity. The basic units can be built up into a high pass or band pass filter, the latter being used in the United Kingdom, as shown in Figure 8.4.

The high voltage capacitor is tuned by the tuning coil to present a low impedance at the signal frequency; the parallel circuit presents a high impedance at the signal frequency while providing a path for the power frequency currents passed by the capacitor.

The complete arrangement is designed as a balanced or unbalanced half-section band pass filter, according to whether the transmission is phase-phase or phase-earth; the power line characteristic impedance, between 400 and 600 ohms, determines the design impedance of the filter.

A typical high voltage capacitor is composed of series-connected rolled foil and paper units immersed in oil and housed in a standard porcelain, enough porcelains being used to enable the whole assembly to withstand the system phase voltage. The overall value of capacitance is usually between 2000 pF and 20,000 pF.

In the United Kingdom, 2000 pF is reckoned to be the minimum value that allows an acceptable bandwidth to be

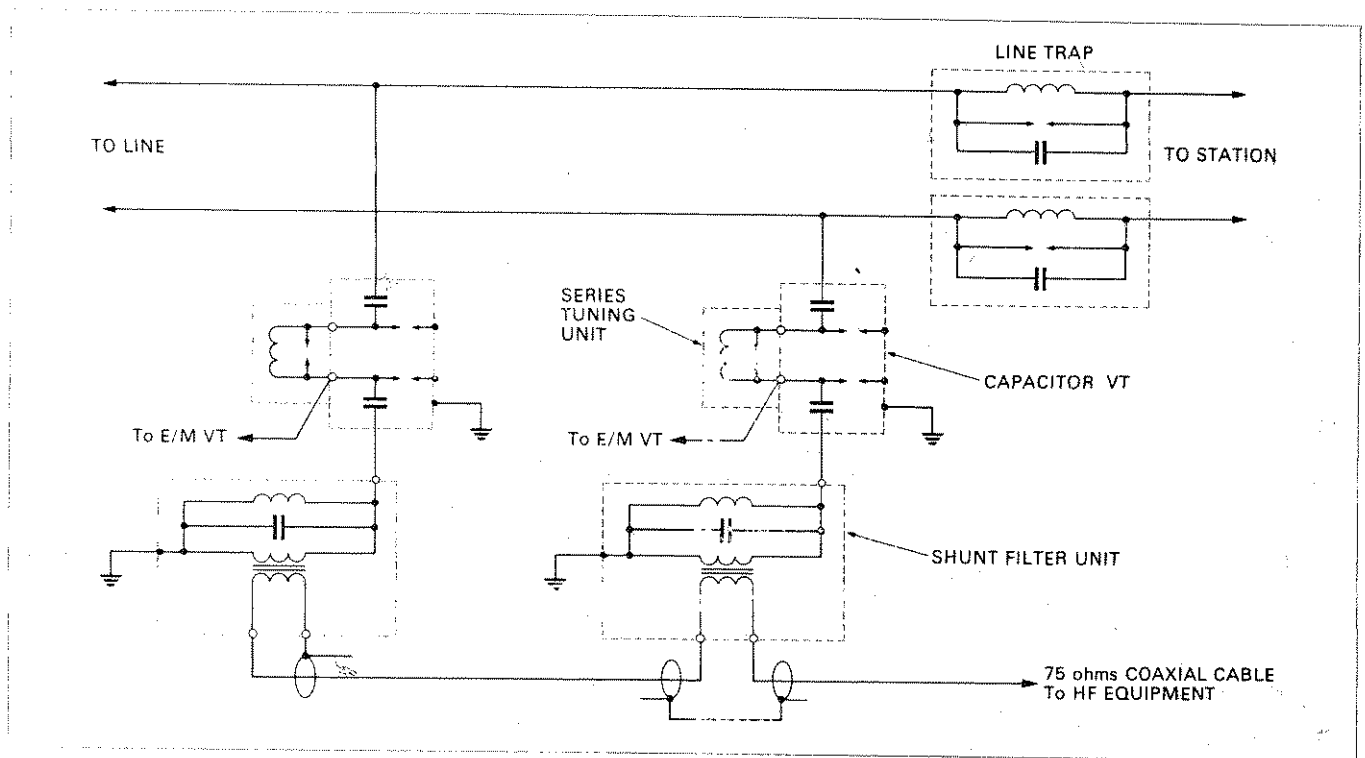


Figure 8.4 Typical phase-to-phase coupling equipment

obtained while at the same time keeping the number of designs required to cover the frequency range 70 to 700kHz down to a small number. This range can be split into eleven bands without difficulty for voltages up to 400kV. The bandwidth increases as the mean frequency to which the filter is tuned in increased.

To raise the efficiency of transmission, it is necessary to minimize the loss of signal into other parts of the power system. This is done with a 'line trap' or 'wave trap', which in its simplest form is a parallel circuit tuned to present a very high impedance to the signal frequency, as shown in Figure 8.4. It is connected in the phase conductor on the station side of the injection equipment.

The coil of the line trap is usually of fairly low inductance, between 0.1mH and 2mH, and must have the same continuous and short circuit rating as the phase conductor in which it is connected, as it will carry most of the current at power frequency. A further requirement of the coil is that its self-capacitance should be of such a value as to put its self-resonant frequency above the highest operating frequency. In the United Kingdom, coils are normally applied with a range of capacitors, so that they can be tuned to any selected frequency within the range 70 to 500kHz.

The response of the single frequency trap is very narrow; such traps are therefore inadequate for use on lines where two or more carrier systems are in operation.

The single frequency line trap may be treated as an integral part of the complete injection equipment to accommodate two or more carrier systems. However, difficulties may arise in an overall design, as, at certain frequencies, the actual station reactance, which is normally capacitive, will tune with the trap, which is inductive below its resonant frequency; the result will be a low impedance across the transmission path, preventing operation at these frequencies. This situation can be avoided by the use of an independent 'double frequency' or 'broad band' trap. A typical circuit is shown, with its impedance characteristic, in Figure 8.5.

This circuit has an overall impedance characteristic that does not rise to the high value at resonance of the single-tune circuit, but does not collapse at any frequency within a fairly wide band. This trap, in fact, behaves as a nearly constant resistance throughout the frequency band.

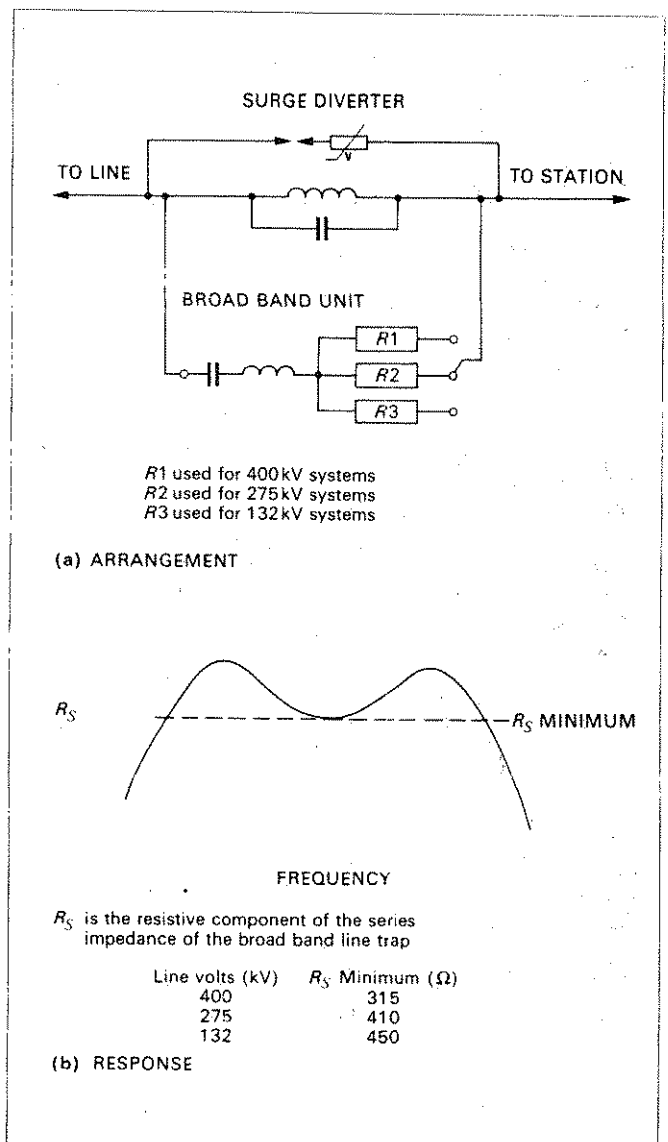


Figure 8.5 Broad band line trap.



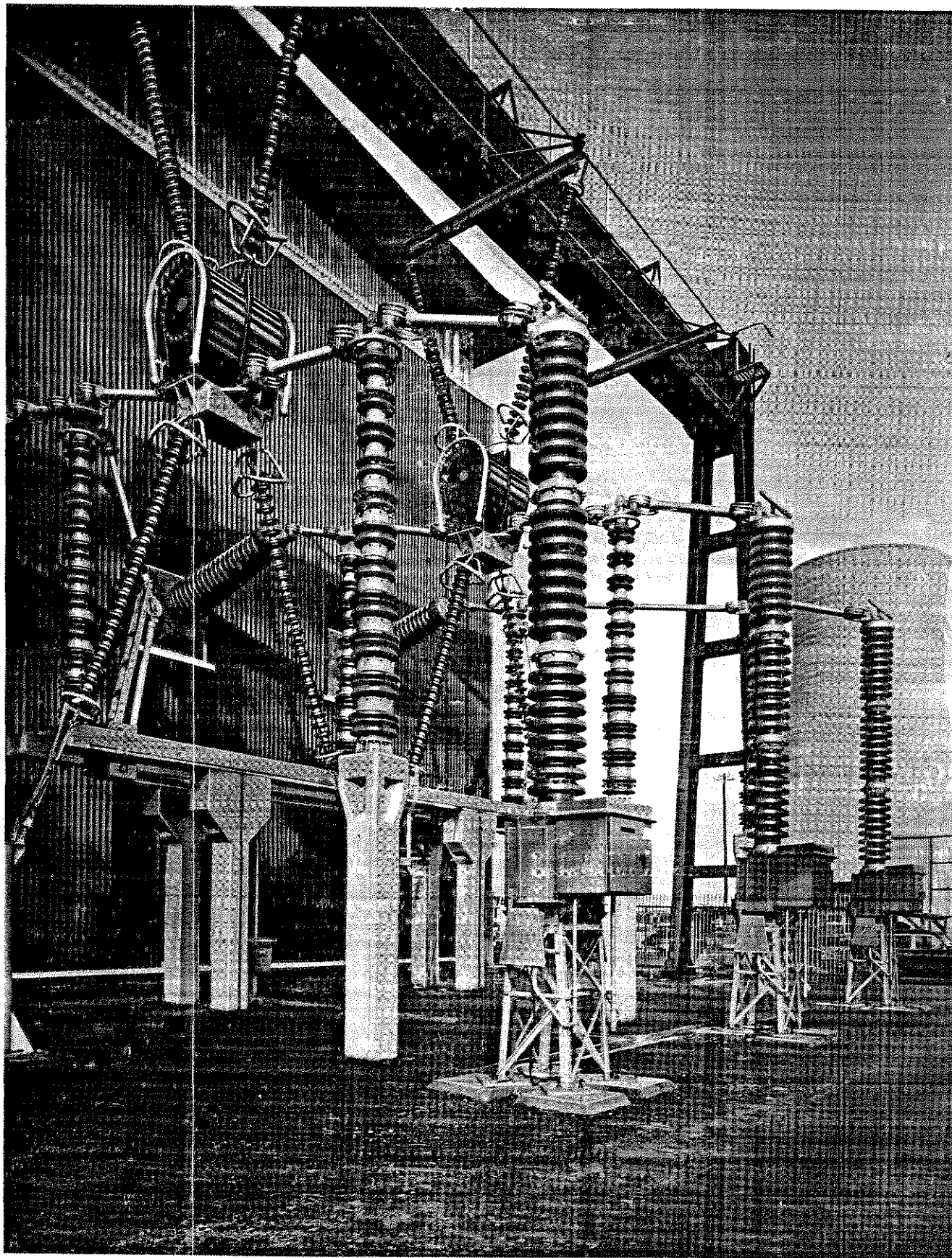


Figure 8.6 Carrier coupling equipment.

The blocking attenuation of this trap is determined by the resistor in the broad band unit. In the United Kingdom the value of the coil for such a trap and the value of the resistor are chosen to be such that, treating the station as a short circuit, a specific mismatching loss, say 3dB, will occur between two frequencies which are sufficiently far apart to cover at least the operating bands of two protection signalling channels at the lower end of the carrier frequency range. Again, bandwidth increases with frequency. The self-capacitance of the main trap coil should be such that its self-resonant frequency is above the mean frequency of the broad band response.

The coupling filter and the carrier equipment are connected by high frequency cable of preferred characteristic impedance 75 ohms. A matching transformer is incorporated in the line coupling filter to match it to the hf cable. Surge diverters are fitted to protect the components against transient high voltages.

The attenuation of a channel is of prime importance in the application of carrier signalling, because it determines the amount of transmitted energy available at the receiving end to overcome noise and interfering voltages. The loss at each line terminal will be 1 to 2dB through the coupling filter, a maximum of 3dB through its broad band trap and not more than 0.5dB per 100 metres through the high frequency cable.

An installation of carrier coupling equipment including capacitor voltage transformers and line traps, in a line-to-line injection arrangement, is shown in Figure 8.6.

The high frequency transmission characteristics of power circuits are good, the loss amounting to 0.02 to 0.2dB per kilometre depending upon line voltage and frequency, the lowest figure being for highest voltage lines (400kV) and lowest signalling frequency (50kHz). Line attenuation is not affected appreciably by rain, but serious increase in loss may occur when the phase conductors are thickly coated with hoar-frost or ice. Attenuations of up to three times the fair weather value have been experienced.

Receiving equipment commonly incorporates automatic control of its gain (AGC) to compensate for variations in attenuation of signals.

The power output of a power line carrier transmitter must be sufficient to ensure that under the worst conditions the signal at the receiver is greater than its rated sensitivity and has a signal/noise ratio better than the limiting figures required for acceptable performance of protection signalling. In addition to signals from other nearby power line carrier systems and radio transmitters, power line carrier receivers are subjected to continuous broadband noise due to corona discharge between the high voltage conductors. Interference at discrete bands of frequencies can be avoided by the choice of suitable operating frequencies and use of highly selective receivers, but corona noise cannot be avoided. Typical single-sideband amplitude modulated carrier communication channels have a receiver bandwidth of 4kHz (equivalent to one voice frequency channel) and respond to a proportion of the corona noise. Typically the noise levels are low, but during periods of bad weather noise levels of up to -10dBm in a 4kHz bandwidth may be encountered on the longest lines operating at the highest voltages. Transmitter power outputs range from about 2 to 100 watts (+50dBm) depending on the operating range and signal/noise ratios required. Maximum levels, or duration of high levels, of transmitted signals may be restricted by national communication authorities to avoid undue interference with radio navigational systems and domestic broadcasting bands.

High noise levels arise from lightning strikes and system fault inception or clearance. Although these are of short duration, lasting only a few milliseconds at the most, they may cause overloading of power line carrier receiving equipment. Signalling systems used for intertripping in

particular must incorporate appropriate security features to avoid maloperations. The most severe noise levels are encountered with operation of the line isolators, and these may last for some seconds. Although maloperation of the associated teleprotection scheme may have little operational significance, since the circuit breaker at one end at least is normally already opened, high security is generally required to cater for noise coupled between parallel lines or passed through line traps from adjacent lines.

Signalling for permissive intertrip applications needs special consideration, as this involves signalling through a power system fault. The increase in channel attenuation due to the fault varies according to the type of fault, but most power authorities select a nominal value, usually between 20 and 30dB, as an application guide. A protection signal boost facility can be employed to cater for an increase in attenuation of this order of magnitude, to maintain an acceptable signal-to-noise ratio at the receiving end, so that the performance of the service is not impaired.

Most direct intertrip applications require signalling over a healthy power system, so boosting is not normally needed. In fact, if a voice frequency intertrip system is operating over a carrier bearer channel, the dynamic operating range of the receiver must be increased to accommodate a boosted signal. This makes it less inherently secure in the presence of noise during a quiescent signalling condition.

#### 8.4.4

##### Radio channels

At first consideration, the wide bandwidth associated with radio frequency transmissions could allow the use of modems (modulator/demodulators) operating at very high data rates. Protection signalling commands could be sent by serial coded messages of sufficient length and complexity to give high security, but still achieve fast operating times. In practice, it is seldom economic to provide radio equipment exclusively for protection signalling, so standard general purpose telecommunications channel equipment is normally adopted.

Typical radio bearer equipment operates at the microwave frequencies of 0.2 to 10GHz. Because of the relatively short range and directional nature of the transmitter and receiver aerial systems at these frequencies, large bandwidths can be allocated without much chance of mutual interference with other systems.

Multiplexing techniques allow a number of channels to share the common bearer medium and exploit the large bandwidth. In addition to voice frequency channels, wider bandwidth channels or data channels may be available, dependent on the particular system. For instance, in analogue systems using frequency division multiplexing, normally up to 12 voice frequency channels are grouped together in basebands at 12-60kHz or 60-108kHz, but alternatively the baseband may be used as a single 48kHz channel. Modern digital systems employing pulse code modulation and time division multiplexing usually provide the voice frequency channels by sampling at 8kHz and quantising to 8 bits; alternatively, access may be available for data at 64k bits/s (equivalent to one voice frequency channel) or higher data rates.

Radio systems are well suited to the bulk transmission of information between control centres and are widely used for this. When the route of the trunk data network coincides with that of transmission lines, channels can often be allocated for protection signalling. More generally radio communication is between major stations rather than the ends of individual lines, because of the need for line-of-sight operation between aerials and other requirements of the network. Roundabout routes involving repeater stations and the addition of pilot channels to interconnect the radio installation and the relay station may be possible, but overall dependability will normally be much lower than

for power line carrier systems in which the communication is direct from one end of the line to the other.

Radio channels are not affected by increased attenuation due to power system faults, but fading has to be taken into account when the signal-to-noise ratio of a particular installation is being considered.

Most of the noise in such a protection signalling system will be generated within the radio equipment itself.

A polluted atmosphere can cause radio beam refraction that will interfere with efficient signalling.

The height of aerial towers should be limited, so that winds and temperature changes have the minimum effect on their position.

#### 8.4.5

##### Optical fibre channels

Optical fibres are fine strands of glass which behave as wave guides for light. This ability to transmit light over considerable distances can be used to provide optical communication links with enormous information carrying capacity and an inherent immunity to electromagnetic interference.

A practical optical cable consists of a central optical fibre which comprises core, cladding and protective buffer coating surrounded by a protective plastic oversheath containing strength members which, in some cases, is enclosed by a layer of armouring.

To communicate information a beam of light is modulated in accordance with the signal to be transmitted. This modulated beam travels along the optical fibre and is subsequently decoded at the remote terminal into the received signal. On/off modulation of the light source is normally preferred to linear modulation since the distortion caused by non-linearities in the light source and detector, as well as variations in received light power, are largely avoided.

The light transmitter and receiver are solid state devices capable of emitting and detecting narrow beams of light at selected frequencies in the low attenuation 850, 1300 and 1550 nanometre spectral windows. The distance over which effective communications can be established depends on the attenuation and dispersion of the communication link and this depends on the type and quality of the fibre and the wavelength of the optical source. Within the fibre there are many modes of propagation with different optical paths which cause dispersion of the light signal and result in pulse broadening. The degrading of the signal in this way can be reduced by the use of 'graded index' fibres which cause the various modes to follow nearly equal paths. The distance over which signals can be transmitted has been significantly increased by the use of 'monomode' fibres which support only one mode of propagation.

With optical fibre channels, communication at data rates of hundreds of megahertz is achievable over a few tens of kilometres, whilst greater distances require the use of repeaters. An optical fibre can be used as a dedicated link between two terminal equipments, or as a multiplexed link which carries all communication traffic such as voice, telecontrol and protection signalling. In the latter case the available bandwidth of a link is divided by means of 'time division multiplexing' (T.D.M.) techniques into a number of channels, each of 64k bits/s (equivalent to one voice frequency channel which typically uses an 8-bit analogue-to-digital conversion at a sampling rate of 8kHz).

The equipments which carry out this multiplexing at each end of a line are known as 'Pulse Code Modulation' (P.C.M.) terminal equipments. This approach is the one adopted by telecommunications authorities and some power system authorities favour its adoption on their private systems, for economic considerations.

Optical fibre communications are quickly becoming

established in the electrical supply industry and many authorities are installing their own links. Whilst such fibres can be laid in cable trenches, there is a strong trend to associate them with the power cables themselves by producing composite cables comprising optical fibres embedded within the conductors, either earth or phase. A new technique, which has the advantage that it can be carried out without the necessity of restringing the conductor, involves wrapping the optical cable helically around the phase conductor.

Optical fibre communication is expected to play an important role in future protection signalling systems, either in the form of dedicated links, or as channels within a multiplexed system. In the latter case the channels could be owned by the power authority or rented from a telecommunications authority.

Further details of Optical Fibre Applications are given in Chapters 10 and 13.

#### 8.4.6

##### General

Diversity of signalling path for a given type of signalling system will increase reliability, and combination of equipments will increase security against maloperation, particularly for direct intertrip applications.

Diversity of transmission medium can also increase reliability, but if tripping is on an 'OR' basis no increase in security will be gained.

Although signalling can be carried out by direct control of the carrier frequency for power line carrier signalling, all the media considered have a common factor, namely that they can make available a voice frequency channel. It is in this channel that a substantially common design of equipment can be used for high speed signalling in power system protection, giving maximum flexibility and diversity of application with the minimum amount of equipment.

#### 8.5

##### METHODS OF SIGNALLING

Various methods are used in protection signalling; not all need be suited to every transmission medium. The methods to be considered briefly are:

- a. D.c. voltage step or d.c. voltage reversals.
- b. Plain tone keyed signals at high and voice frequencies.
- c. Frequency shift keyed signals involving two or more tones at high and voice frequencies.

##### 8.5.1

###### D.c. voltage signalling

A d.c. voltage step or d.c. voltage reversals may be used to convey a signalling instruction between protection relaying points in a power system, but these are suited only to private pilot wires, where low speed signalling is acceptable, with its inherent security.

##### 8.5.2

###### Plain tone signals

Plain high frequency signals can be used successfully for the signalling of blocking information over a power line. A normally quiescent power line carrier equipment can be dedicated entirely to the transfer of teleprotection blocking commands. Phase comparison power line carrier unit protection schemes often use such equipment and take advantage of the very high speed and dependability of the signalling system. The special characteristics of dedicated 'on/off' keyed carrier systems are discussed in more detail in Chapter 10. A relatively insensitive receiver is used to discriminate against noise on an amplitude basis, and for some applications the security may be satisfactory for permissive tripping, particularly if the normal high speed operation of about 6ms is sacrificed by the addition of delays. The need for regular reflex testing of a normally

quiescent channel usually precludes any use for intertripping.

Plain tone power line carrier signalling systems are particularly suited to providing the blocking commands often associated with the protection of multi-ended feeders, as described in Chapter 13. A blocking command sent from one end can be received simultaneously at all the other ends, using a single power line carrier channel. Other signalling systems usually require discrete communication channels between each of the ends or involve repeaters, leading to decreased dependability of the blocking command.

Plain voice frequency signals can be used for blocking, permissive intertrip and direct intertrip applications for all transmission media but operation is at such a low signal level that security from maloperation is not very good. Operation in the 'tone on' to 'tone off' mode gives the best channel monitoring, but offers little security, to obtain a satisfactory performance the output must be delayed. This results in relatively slow operation: 70 milliseconds for permissive intertripping, 180 milliseconds for direct intertripping.

### 8.5.3

#### Frequency shift keyed signals

Frequency shift keyed high frequency signals can be used over a power line carrier link to give short operating times (15 milliseconds for blocking and permissive intertripping, 30 milliseconds for direct intertripping) for all applications of protection signalling. The required amount of security can be achieved by using a broad band noise detector to monitor the actual operational signalling equipment.

Frequency shift keyed voice frequency signals can be used for all protection signalling applications over all transmission media. Frequency modulation techniques make possible an improvement in performance, because amplitude limiting rejects the amplitude modulation component of noise, leaving only the phase modulation components to be detected.

The operational protection signal may consist of one sequence codes with, say, three tones, or a multi-bit code using two discrete tones for successive bits, or of a single frequency shift.

Modern high speed systems use multi-bit code or single frequency shift techniques.

Complex codes are used to give the required degree of security in direct intertrip schemes: the short operating

times needed may result in uneconomical use of the available voice frequency spectrum, particularly if the channel is not exclusively employed for protection signalling. As noise power is directly proportional to bandwidth, a larger bandwidth causes an increase in the noise level admitted to the detector, making operation in the presence of noise more difficult. So, again, it is difficult to obtain both high dependability and high security.

The single frequency shift technique has advantages where fast signalling is needed for blocked distance and permissive intertrip applications. It has little inherent security, but additional circuits responsive to every type of interference can give acceptable security. This system does not require a channel capable of a high transmission rate, as the frequency changes once only; the bandwidth can therefore be narrower than in coded systems, giving better noise rejection as well as being advantageous if the channel is shared with telemetry and control signalling, which will inevitably be the case if a power line carrier bearer is employed.

### 8.6

#### PRACTICAL SIGNALLING SYSTEMS

Two practical systems made available by GEC ALSTHOM Measurements are described in this section.

One system employs signalling at voice frequencies and can therefore be applied wherever voice frequency channels are available, while the other signals over optical fibres in place of pilots.

A keyed carrier equipment type K10 is also available which uses the same transmitter and receiver as the phase comparison equipment type P10 described in Section 10.11.

#### 8.6.1

##### High speed protection signalling system, type SD15

This is a general purpose teleprotection system suitable for the transfer of blocking, permissive trip and direct trip (intertrip) commands required by protective relay schemes. Operation is at voice frequencies and commands are conveyed by using the frequency shift principle.

The equipment can operate over any medium which provides a voice frequency channel, such as pilot wires, telephone (speech band) circuits, power line carrier, radio or optical fibre multiplex equipment.

The narrow bandwidth of only 480Hz allows the combina-

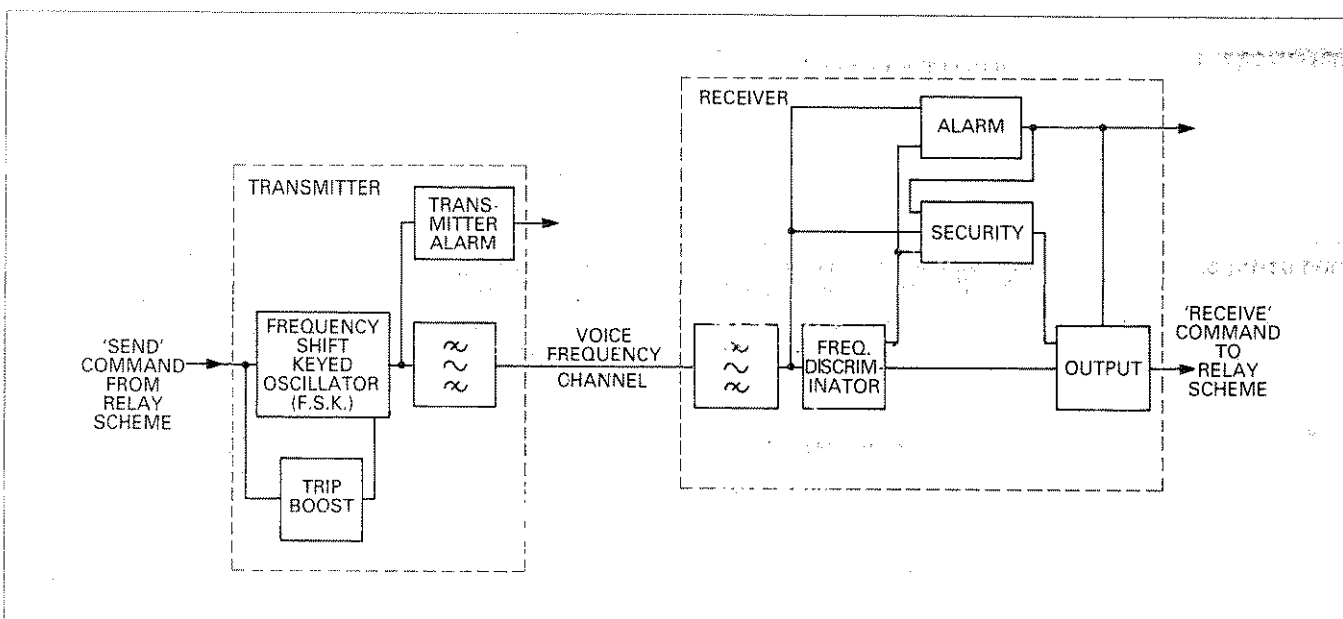


Figure 8.7 SD15 block diagram.



tion of a number of signalling channels on a single communication channel, or a speech-plus-signalling arrangement where the communication channel bandwidth extends up to nominally 4kHz.

### **Operation**

A one-way (simplex) signalling system is adequate for some intertripping applications, but usually a two-way (duplex) system is required and this is provided by a transmitter and receiver housed in a common single subrack, utilising a 4-wire telecommunication circuit.

The transmitter normally transmits a continuous guard frequency which holds the receiver in the non-operated state and also provides the basis for continuous monitoring of the telecommunication circuit as well as much of the signalling equipment. When required to send a command, the transmitter frequency is shifted rapidly to a trip frequency. A high speed frequency discriminator circuit in the receiver responds to this frequency to provide an output when certain time delays and other security restraints have been satisfied. A block diagram of the equipment is shown in Figure 8.7.

### **Protection relay interfaces**

High speed reed relays provide 2kV isolation between the relay schemes which send or receive the command and the signalling equipment.

### **Voice frequency channel interfaces**

Band pass filters match the equipment to a voice frequency channel of 600 ohms nominal impedance at the operating frequencies and present high impedances to frequencies in the stop band. Frequency division multiplexing of a number of SD15 equipments on a single voice frequency channel is possible therefore, using direct parallel connections. Transmissions satisfy the requirements of British Telecommunications and the equipment has been approved for operation on their rented speechband circuits. The balanced output has 500V isolation from earth which is generally satisfactory for installation near to vf channel equipment. An isolating transformer unit with 15kV isolation is available for use when operating over pilots.

Maximum transmitter output is +8dBm and the minimum acceptable level at the receiver is -33dBm, giving a maximum range, or loss on a private pilot, of 41dB. Typical applications on other media use transmitter and receiver levels of -20dBm. Trip boosting can be used to increase the signal level up to maximum while the command is being sent, so a boost of 28dB is usually available.

Either of the two signalling frequencies may be selected for use for the guard function. At a site where a number of vf channels pass through a common distribution panel, inadvertent crossing of pilots might occur. The facility to select 'guard low' or 'guard high' provides additional channel coding which can be used to ensure that alarms are given and incorrect outputs avoided. Where a dual channel arrangement is used for the highest security, the use of 'guard low' on one channel and 'guard high' on the other avoids possibility of both channels operating at the same time when a frequency shift is introduced by a bearer channel during power-up or changeover of master oscillators.

### **Frequency discrimination**

The receiver bandpass filter passes the operation frequencies and rejects all other tones due to multiplexing as well as much of the broad band noise associated with any voice frequency channel. The signal is squared up (or fully limited) to reduce the sensitivity to amplitude variations and then applied to the frequency discriminator. The period is compared with that of high stability timers and digital techniques are exploited to give guard and trip outputs for

frequencies in narrow bands centred on the nominal guard and trip frequencies, as well as other outputs when frequencies outside these bands are detected. The security, alarm and output stages are continually updated (every 2 cycles or 1ms at 2000Hz) with information on the frequency which is being received, without the delays which are often associated with detection using narrow band filters.

### **Security and alarms**

The frequency discriminator responds rapidly to any frequency shifts and if used directly as the equipment output could provide overall contact-to-contact operating times of about 9ms. Such a system might perform adequately when operating under ideal conditions, but would probably prove unsatisfactory when subjected to the high levels of noise, short circuits or open circuits on pilots, or power supply interruptions which are often encountered in practice.

Security circuits detect the presence of abnormal signals, and their outputs control the operation of the output stage. Operation is permitted only when the signal has satisfied criteria for level, frequency and freedom from interference.

Alarm circuits also detect the presence of abnormal signal or excessive noise. LED indications are provided on the equipment, and if the condition persists for more than a few seconds a 'Channel Fail' relay operates to give external alarms. If desired, the alarm may be used to give further security or force the output into either of its states.

High and low level detectors provide security during high levels of noise or signal failure. The settings are usually at  $\pm 9$ dB relative to the normal level with alarms being provided at  $\pm 6$ dB. This provides a 3dB safety margin so that advance warning of slow changes in signal level is provided before the level becomes unacceptable.

At initial power-up or connection of the channel a timer ensures that no operation can occur until guard frequency has been detected consistently at a signal level above the low level detector setting for more than 200ms. This provides high security when channels are tested with oscillators and useful alarms if pilots are crossed, particularly when different channels are used or the 'guard low', 'guard high' feature is exploited. For blocking applications, the output is not inhibited by the timer since the highest dependability at all times is usually considered to be more important than any slight risk of false outputs.

Operation of the output stage is permitted only when trip frequencies have been detected consistently for a preset time interval. Short excursions of frequency into the trip band caused by high levels of noise are disregarded. Variation of the time interval over the range 5 to 25ms permits the selection of a decision level or bias to suit the varying degrees of security required for applications ranging from permissive to direct tripping. For blocking applications, similar techniques are used, but the bias is reversed and applied only when a command has been received. This ensures that resetting is permitted only when guard frequencies have been detected consistently for an appropriate time and therefore maintains the blocking command with high dependability.

Alarms are given if neither of the signalling frequencies are detected or if noise or interfering tones cause significant amplitude modulation of the signal. The voice frequency channel and much of the signalling equipment is continuously monitored and alarms are provided whenever the performance might be impaired. Optional test facilities are available for end-to-end or loop testing.

### **Performance**

Security, dependability and operating time are interdependent parameters for SD15. Time delay settings can be selected for optimum performance for each application.

based on the characteristics of the system when subjected to white noise. Typical performance is shown in Table 8.1.

| Typical application     | Operating time (ms) |          | Reset time (ms) |     |      |
|-------------------------|---------------------|----------|-----------------|-----|------|
|                         | $t_o$               | $t_{ac}$ | min             | nom | max  |
| Intertrip (Direct trip) |                     |          |                 |     |      |
| Single channel          | 35                  | 60       |                 | 40  |      |
| Dual channel            | 25                  | 30       |                 | 40  |      |
| Permissive trip         |                     |          |                 |     |      |
| Under-reach             | 20                  | 25       |                 | 40  |      |
| Over-reach              | 20                  | 25       |                 | 15  | *20* |
| Blocking                | 15                  | *18*     | *10*            | 15  | 25   |

$t_o$  = operating time without noise.  
 $t_{ac}$  = maximum operating time with white noise. Mean noise level measured in 4kHz bandwidth 6dB below signal. The probability that  $t_{ac}$  is exceeded ( $P_{MC}$ ) ranges from  $10^{-2}$  for intertripping to  $10^{-6}$  for blocking.  
 \* Times which normally influence the choice of timer settings on associated protection relays.

Table 8.1 Typical performance of SD15

For intertripping applications, operating times are chosen for the highest security. The probability of an unwanted command ( $P_{UC}$ ) is less than  $10^{-5}$  when the system is subjected to bursts of white noise lasting 200ms at the most onerous noise level. For permissive tripping  $P_{UC}$  is less than  $10^{-3}$  when the mean level of noise bursts is up to 6dB above the signal. The emphasis for blocking performance is on high dependability and speed of operation; however a  $P_{UC}$  of  $10^{-3}$  is achieved for mean levels of noise bursts up to the signal level.

### 8.6.2

#### Teleprotection signalling system using optical fibre channel

This system provides very high speed signalling of intertrip or other teleprotection commands. Communication is via optical fibres, with the commands being conveyed by coded digital messages transmitted as a series of light pulses.

High data rates are employed, allowing up to five teleprotection commands and five general purpose data channels to be provided by a single equipment and fibre.

#### Operation

Signalling commands from the protection relay scheme enter the signalling equipment via opto-isolators. Each of the five commands is coded as two data input bits. In this way the five commands are converted to 10 data bits to which are added the inputs on the five data channels, giving a total of 15 data bits. An eight bit parity code is generated from the data, so with a start bit and end of

message bit in addition the total message length is 25 bits, to the format shown in Figure 8.8.

For transmission, the message is scanned at a data rate of 38.4 kilobits per second and each bit is encoded using Manchester encoding. This coding allows the receiver to generate its own clockpulse from the serially transmitted data since a transition occurs for every bit. A code violation or absence of transition is introduced at the start and finish of each scan to allow synchronization of the complete message.

The encoded data is used to key an enhanced LED transmitter which is coupled to an optical fibre. At the receiving end the light signals are detected as pulses which are decoded and the data is reformed. Decoding the states of the two bits associated with each teleprotection command provides the control for high speed output reed relays.

The optical components operate at a wavelength of 850 nanometres. Using multi-mode graded index optical fibres having core and cladding diameters of 50 and 125 micrometres respectively, and an assumed loss of just under 4dB per km, the transmission distance is at least 6km.

At the data rate of 38.4 kilobits per second each message of 25 bits takes approximately 0.65ms to be transmitted. Any change in input data results in a corresponding change in output data within the time taken for two complete scans, giving a maximum signalling delay of approximately 1.3ms.

#### Security

The optical fibre medium forms an interference-free data transmission link. Accordingly, the system is not subjected to the hazards of adverse noise, and the resultant corruption of data associated with signalling on any other medium. The system must however tolerate breaks or disconnection and reconnection of the fibre, power-up/down and the adverse noise normally encountered in the protection relay environment, without producing unwanted commands.

Detection of errors in the data message is provided by an 8 bit parity check. In principle the input data is treated as a binary number which is divided by a fixed number giving an eight bit remainder. The remainder or cyclic redundancy code is transmitted along with the input data. A similar division is made at the receiving end. Providing there are no errors during transmission the calculated and received parity codes are identical and the data is accepted and passed to the output register. If a transmission is corrupted, a discrepancy between the calculated and received parity codes occurs and updating of the output register is inhibited, so avoiding unwanted commands. Alarms are provided if errors are detected on three successive transmissions.

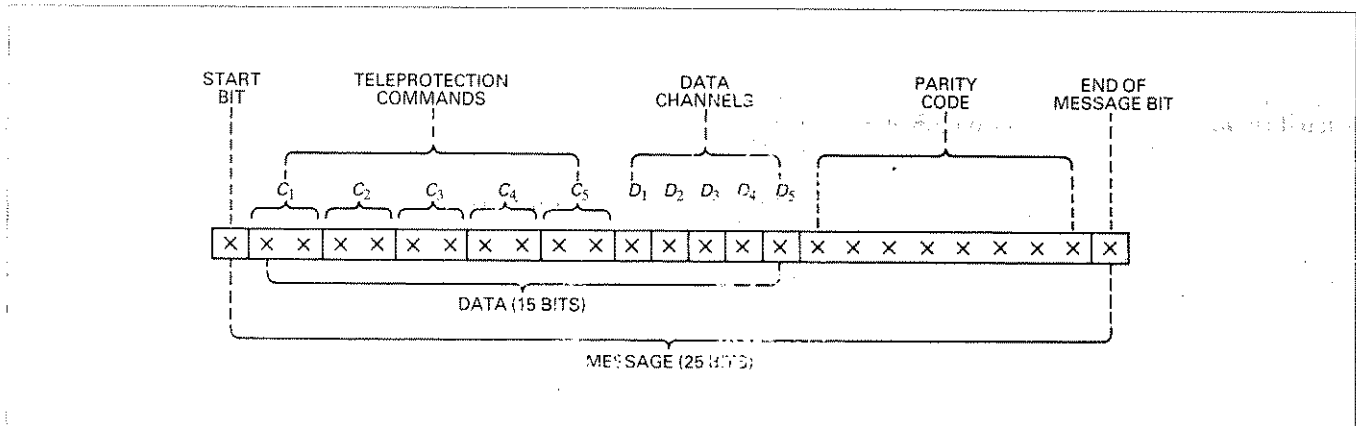


Figure 8.8 Teleprotection message format.

Additional security results from the use of Manchester encoding and a fixed scan rate, since these give clock pulse generation on each bit of received data and a bit time which is normally constant. Timers are arranged to discriminate against transitions occurring at less than 75% or greater than 125% of the nominal bit time. Any variation from the normal message length of 25 bits is detected by performing a bit count on each message.

### **Performance**

The operating time for a teleprotection command is less than 10ms, and this is achieved with both extremely high security and dependability.





# Overcurrent protection for phase and earth faults

- 9.1 Introduction.
- 9.2 Co-ordination procedure.
- 9.3 Principles of time/current grading.
- 9.4 Grading margin.
- 9.5 Standard I.D.M.T. overcurrent relays.
- 9.6 Combined I.D.M.T. and high set instantaneous overcurrent relays.
- 9.7 Very inverse overcurrent relays.
- 9.8 Extremely inverse overcurrent relays.
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- 9.10 Voltage controlled overcurrent relays (type CDV22).
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- 9.12 Summary.
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## 9.1 INTRODUCTION

Protection against excess current was naturally the earliest protective system to evolve. From this basic principle has been evolved the graded overcurrent system, a discriminative fault protection. This should not be confused with 'overload' protection, which normally makes use of relays that operate in a time related in some degree to the thermal capability of the plant to be protected. Overcurrent protection, on the other hand, is directed entirely to the clearance of faults, although with the settings usually adopted some measure of overload protection is obtained.

## 9.2 CO-ORDINATION PROCEDURE

Correct current relay application requires a knowledge of the fault current that can flow in each part of the network. Since large scale tests are normally impracticable, system analysis must be used. It is generally sufficient to use machine transient reactances  $X'_d$  and to work on the instantaneous symmetrical currents. The data required for a relay setting study are:

- a. A one-line diagram of the power system involved, showing the type and rating of the protective devices and their associated current transformers.
- b. The impedances in ohms, per cent or per unit, of all power transformers, rotating machines and feeder circuits.
- c. The maximum and minimum values of short circuit currents that are expected to flow through each protective device.
- d. The starting current requirements of motors and the starting and stalling times of induction motors.
- e. The maximum peak load current through protective devices.
- f. Decrement curves showing the rate of decay of the fault current supplied by the generators.
- g. Performance curves of the current transformers.

The relay settings are first determined so as to give the shortest operating times at maximum fault levels and then checked to see if operation will also be satisfactory at the minimum fault current expected. It is always advisable to plot the curves of relays and other protective devices, such as fuses, that are to operate in series, on a common scale. It is usually more convenient to use a scale corresponding

to the current expected at the lowest voltage base or to use the predominant voltage base. The alternatives are a common MVA base or a separate current scale for each system voltage.

The basic rules for correct relay co-ordination can generally be stated as follows:

- i. Whenever possible, use relays with the same operating characteristic in series with each other
- ii. Make sure that the relay farthest from the source has current settings equal to or less than the relays behind it, that is, that the primary current required to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it.

### 9.3

#### 9.3.1 TIME DELAY OF TIME/CURRENT

Among the various possible methods used to achieve correct relay co-ordination are those using either time or over-current or a combination of both time and overcurrent. The common aim of all three methods is to give correct discrimination. That is to say, each one must select and isolate only the faulty section of the power system network, leaving the rest of the system undisturbed.

#### 9.3.1

##### Discrimination by time

In this method an appropriate time interval is given by each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to the fault opens first. A simple radial distribution system is shown in Figure 9.1, to illustrate the principle.

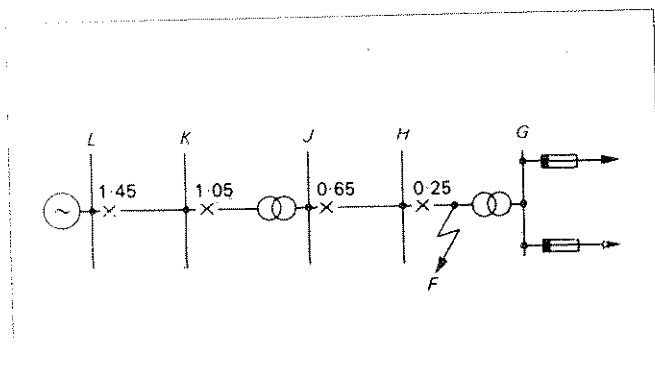


Figure 9.1 Radial system with time discrimination.

Circuit breaker protection is provided at H, J, K and L, that is, at the infeed end of each section of the power system. Each protection unit comprises a definite time delay over-current relay in which the operation of the current sensitive element simply initiates the time delay element. Provided the setting of the current element is below the fault current value this element plays no part in the achievement of discrimination. For this reason, the relay is sometimes described as an 'independent definite time delay relay' since its operating time is for practical purposes independent of the level of overcurrent.

It is the time delay element, therefore, which provides the means of discrimination. The relay at H is set at the shortest time delay permissible to allow a fuse to blow for a fault on the secondary side of transformer G. Typically, a time delay of 0.25s is adequate.

If a fault occurs at F, the relay at H will operate in 0.25s and the subsequent operation of the circuit breaker at H will clear the fault before the relays at J, K and L have time to operate. The main disadvantage of this method of discrimination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest.

### 9.3.2

##### Discrimination by current

Discrimination by current relies on the fact that the fault current varies with the position of the fault because of the difference in impedance values between the source and the fault. Hence, typically, the relays controlling the various circuit breakers are set to operate at suitably tapered values such that only the relay nearest to the fault trips its breaker. Figure 9.2 illustrates the method.

For a fault at  $F_1$ , the system short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1}} A$$

where  $Z_S$  = source impedance

$$= \frac{11^2}{250}$$

$$= 0.485 \text{ ohms}$$

$$Z_{L1} = \text{cable impedance between J and H}$$

$$= 0.24 \text{ ohms}$$

$$\text{Hence } I = \frac{6350}{0.725}$$

$$= 8800 A$$

So a relay controlling the circuit breaker at J and set to operate at a fault current of 8800 A would in simple theory protect the whole of the cable section between J and H. However, there are two important practical points which affect this method of co-ordination.

i. It is not practical to distinguish between a fault at  $F_1$  and a fault at  $F_2$ , since the distance between these points can be only a few metres, corresponding to a change in fault current of approximately 0.1%.

ii. In practice, there would be variations in the source fault level, typically from 250 MVA to 130 MVA. At this lower fault level the fault current would not exceed 6800 A even for a cable fault close to J, so a relay set at 8800 A would not protect any of the cable section concerned.

Discrimination by current is therefore not a practical proposition for correct grading between the circuit breakers at J and H. However, the problem changes appreciably when there is significant impedance between the two circuit breakers concerned. This can be seen by considering the grading required between the circuit breakers at H and G in Figure 9.2. Assuming a fault at  $F_4$ , the short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1} + Z_{L2} + Z_T}$$

where  $Z_S$  = source impedance

$$= \frac{11^2}{250}$$

$$= 0.485 \text{ ohms}$$

$$Z_{L1} = \text{cable impedance between J and H}$$

$$= 0.24 \text{ ohms}$$

$$Z_{L2} = \text{cable impedance between H and 4 MVA transformer}$$

$$= 0.04 \text{ ohms}$$

$$Z_T = \text{transformer impedance}$$

$$= 0.07 \left( \frac{11^2}{4} \right)$$

$$= 2.12 \text{ ohms}$$

$$\text{Hence } I = \frac{6350}{2.885}$$

$$= 2200 A$$

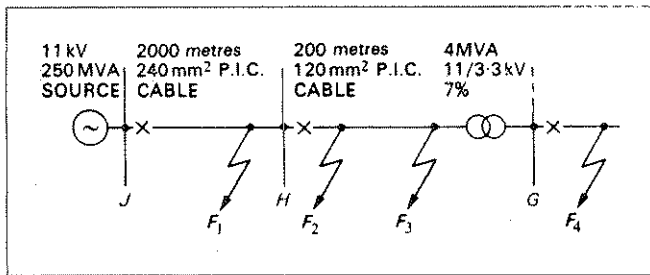


Figure 9.2 Radial system with current discrimination.

For this reason, a relay controlling the circuit breaker at *H* and set to operate at a current of 2200 A plus a safety margin would not operate for a fault at *F*<sub>4</sub> and would thus discriminate with the relay at *G*. Assuming a safety margin of 20% to allow for relay errors and a further 10% for

variations in the system impedance values, it is reasonable to choose a relay setting of  $1.3 \times 2200$ , that is, 2860 A for the relay at *H*. Now, assuming a fault at *F*<sub>3</sub>, that is, at the end of the 11 kV cable feeding the 4 MVA transformer, the short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1} + Z_{L2}}$$

Thus, assuming a 250 MVA source fault level:

$$I = \frac{6350}{0.485 + 0.24 + 0.04} = 8300 \text{ A}$$

Alternatively, assuming a source fault level of 130 MVA:

$$I = \frac{6350}{0.93 + 0.24 + 0.04} = 5250 \text{ A}$$

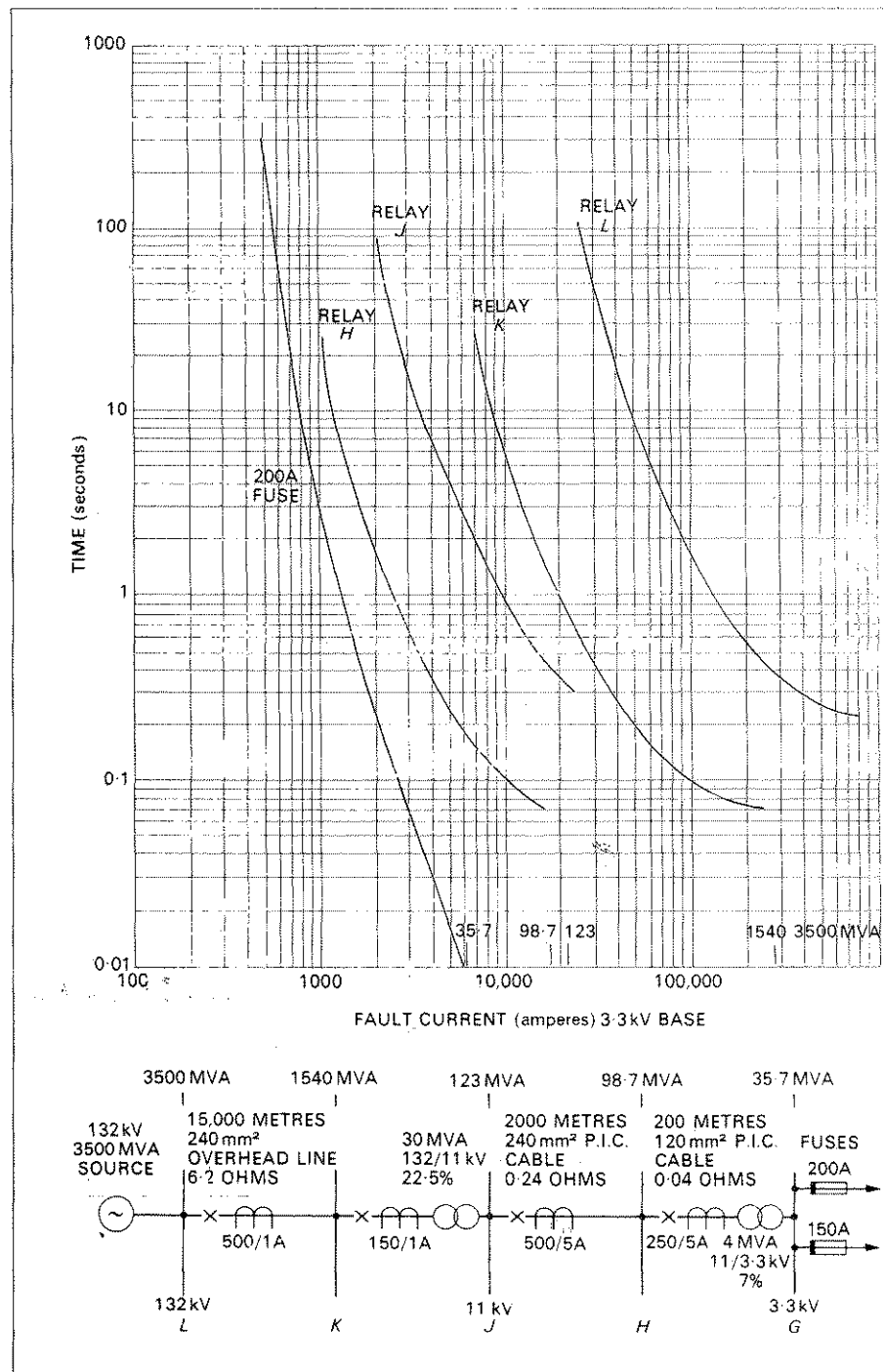


Figure 9.3 Time and current grading.

In other words, for either value of source level, the relay at *H* would operate correctly for faults anywhere on the 11 kV cable feeding the transformer.

### 9.3.3

#### Discrimination by both time and current

Each of the two methods described so far has a fundamental disadvantage. In the case of discrimination by time alone, the disadvantage is due to the fact that the more severe faults are cleared in the longest operating time. Discrimination by current can be applied only where there is an appreciable impedance between the two circuit breakers concerned.

It is because of the limitations imposed by the independent use of either time or current co-ordination that the inverse time overcurrent relay characteristic has evolved. With this characteristic, the time of operation is inversely proportional to the fault current level and the actual characteristic is a function of both 'time' and 'current' settings. The advantage of this method of relay co-ordination may be best illustrated by the system shown in Figure 9.3, which is identical to that shown in Figure 9.1 except that typical system parameters have been added.

In order to carry out a system analysis, before a relay co-ordination study of the system shown in Figure 9.3, it is necessary to refer all the system impedances to a common base and thus, using 10 MVA as the reference base, we have:

$$\begin{aligned}
 &4 \text{ MVA transformer} &&= 7 \times \frac{10}{4} \\
 &\text{percentage impedance on} && \\
 &10 \text{ MVA base} &&= 17.5\% \\
 &11 \text{ kV cable between } H \text{ and } G &&= \frac{0.04 \times 100 \times 10}{11^2} \\
 &\text{percentage impedance on} && \\
 &10 \text{ MVA base} &&= 0.33\% \\
 &11 \text{ kV cable between } J \text{ and } H &&= \frac{0.24 \times 100 \times 10}{11^2} \\
 &\text{percentage impedance on} && \\
 &10 \text{ MVA base} &&= 1.98\% \\
 &30 \text{ MVA transformer} &&= 22.5 \times \frac{10}{30} \\
 &\text{percentage impedance on} && \\
 &10 \text{ MVA base} &&= 7.5\% \\
 &132 \text{ kV overhead line} &&= \frac{6.2 \times 100 \times 10}{132^2} \\
 &\text{percentage impedance on} && \\
 &10 \text{ MVA base} &&= 0.36\% \\
 &132 \text{ kV source} &&= \frac{100 \times 10}{3500} \\
 &\text{percentage impedance on} && \\
 &10 \text{ MVA base} &&= 0.29\%
 \end{aligned}$$

The graph in Figure 9.3 illustrates the use of 'discrimination curves', which are an important aid to satisfactory protection co-ordination. In this example, a voltage base of 3.3 kV has been chosen and the first curve plotted is that of the 200 A fuse, which is assumed to protect the largest outgoing 3.3 kV circuit. Once the operating characteristic of the highest rated 3.3 kV fuse has been plotted, the grading of the overcurrent relays at the various substations of the radial system is carried out as follows.

#### Substation H

CT ratio 250/5A

Relay overcurrent characteristic assumed to be extremely inverse, as for the type CDG 14 relay. This relay must discriminate with the 200 A fuse at fault levels up to:

$$\frac{10 \times 100}{17.5 + 0.33 + 1.98 + 7.5 + 0.36 + 0.29} = 35.7 \text{ MVA}$$

that is, 6260 A at 3.3 kV or 1880 A at 11 kV. The operating

characteristics of the CDG 14 relay show that at a plug setting of 100%, that is, 250 A and 4.76 MVA at 11 kV, and at a time multiplier setting of 0.2, suitable discrimination with the 200 A fuse is achieved.

#### Substation J

CT ratio 500/5A

Relay overcurrent characteristic assumed to be extremely inverse, as for the type CDG 14 relay. This relay must discriminate with the relay in substation *H* at fault levels up to:

$$\frac{10 \times 100}{1.98 + 7.5 + 0.36 + 0.29} = 98.7 \text{ MVA}$$

that is, 17,280 A at 3.3 kV or 5180 A at 11 kV. The operating characteristics of the CDG 14 relay show that at a plug setting of 100%, that is, 500 A and 9.52 MVA at 11 kV, and at a time multiplier setting of 0.7, suitable discrimination with the relay at substation *H* is achieved.

#### Substation K

CT ratio 150/1 A

Relay overcurrent characteristic assumed to be extremely inverse, as for the type CDG 14 relay. This relay must discriminate with the relay in substation *J* at fault levels up to:

$$\frac{10 \times 100}{7.5 + 0.36 + 0.29} = 123 \text{ MVA}$$

that is, 21,500 A at 3.3 kV or 538 A at 132 kV. The operating characteristics of the CDG 14 relay show that at a plug setting of 100%, that is, 150 A and 34.2 MVA at 132 kV and at a time multiplier setting of 0.25, suitable discrimination with the relay at substation *J* is achieved.

#### Substation L

CT ratio 500/1 A

Relay overcurrent characteristic assumed to be extremely inverse, as for the type CDG 14 relay. This relay must discriminate with the relay in substation *K* at fault levels up to:

$$\frac{10 \times 100}{0.36 + 0.29} = 1540 \text{ MVA}$$

that is, 270,000 A at 3.3 kV or 6750 A at 132 kV. The operating characteristics of the CDG 14 relay show that at a plug setting of 100%, that is, 500 A and 114 MVA at 132 kV, and at a time multiplier setting of 0.9, suitable discrimination with the relay at substation *K* is achieved.

A comparison between the relay operating times shown in Figure 9.1 and the times obtained from the discrimination curves of Figure 9.3 at the maximum fault level reveals significant differences. These differences can be summarized as follows:

| Relay    | Fault level (MVA) | Time from Figure 9.1 (seconds) | Time from Figure 9.3 (seconds) |
|----------|-------------------|--------------------------------|--------------------------------|
| <i>H</i> | 98.7              | 0.25                           | 0.07                           |
| <i>J</i> | 123               | 0.65                           | 0.33                           |
| <i>K</i> | 1540              | 1.05                           | 0.07                           |
| <i>L</i> | 3500              | 1.45                           | 0.25                           |

These figures show that for faults close to the relaying points the inverse time characteristic can achieve appreciable reductions in fault clearance times. Even for faults at the remote ends of the protected sections, reductions in

fault clearance times are still obtained, as shown by the following table:

| Relay | Fault level (MVA) | Time from Figure 9.3 (seconds) |
|-------|-------------------|--------------------------------|
| H     | 35.7              | 0.17                           |
| J     | 98.7              | 0.42                           |
| K     | 123               | 0.86                           |
| L     | 1540              | 0.39                           |

To finalize the co-ordination study it is instructive to assess the average operating time for each extremely inverse overcurrent relay at its maximum and minimum fault levels, and to compare these with the operating time shown in Figure 9.1 for the definite time overcurrent relay.

| Relay | Fault level (max./min. MVA) | Times from Figure 9.3 (min./max. seconds) | Average time (seconds) |
|-------|-----------------------------|-------------------------------------------|------------------------|
| H     | 98.7/35.7                   | 0.07/0.17                                 | 0.12                   |
| J     | 123/98.7                    | 0.33/0.42                                 | 0.375                  |
| K     | 1540/123                    | 0.07/0.86                                 | 0.465                  |
| L     | 3500/1540                   | 0.25/0.39                                 | 0.32                   |

This comparison clearly shows that when there is a large variation in fault level all along the system network the overall performance of the inverse time overcurrent relay is far superior to that of the definite overcurrent relay.

## 9.4 GRADING MARGIN

The time interval between the operation of two adjacent relays depends upon a number of factors:

- The fault current interrupting time of the circuit breaker.
- The overshoot time of the relay.
- Errors.
- Final margin on completion of operation.

### 9.4.1 Circuit breaker interrupting time

The circuit breaker interrupting the fault must have completely interrupted the current before the discriminating relay ceases to be energized.

### 9.4.2 Overshoot

When the relay is de-energized, operation may continue for a little longer until any stored energy has been dissipated. For example, an induction disc relay will have stored kinetic energy in the motion of the disc; static relay circuits may have energy stored in capacitors. Relay design is directed to minimizing and absorbing these energies, but some allowance is usually necessary.

The overshoot time is not the actual time during which some forward operation takes place, but the time which would have been required by the relay if still energized to achieve the same amount of operational advance.

### 9.4.3 Errors

All measuring devices such as relays and current transformers are subject to some degree of error. The operating time characteristic of either or both relays involved in the grading may have a positive or negative error, as may the current transformers, which can have phase and ratio errors due to the exciting current required to magnetize their cores. This does not, however, apply to independent definite time delay overcurrent relays.

Relay grading and setting is carried out assuming the accuracy of the calibration curves published by manufacturers, but since some error is to be expected, some tolerance must be allowed.

### 9.4.4 Final margin

After the above allowances have been made, the discriminating relay must just fail to complete its operation. Some extra allowance, or safety margin, is required to ensure that a satisfactory contact gap (or equivalent) remains.

### 9.4.5 Recommended overall time interval

The total interval required to cover the above items depends on the operating speed of the circuit breakers and the relay performance. At one time 0.5s was a normal grading margin. With faster modern circuit breakers and lower relay overshoot times 0.4s is reasonable, while under the best conditions even lower intervals may be practical.

The use of a fixed grading margin is popular, but in some instances it is better to calculate the required value for each relay location. This more precise margin comprises a fixed time, covering circuit breaker fault interrupting time, relay overshoot time and a safety margin, plus a variable time which allows for relay and CT errors.

For many circuit breaker designs the interrupting time is typically 0.1s, but the equivalent time for some vacuum circuit breakers is only 0.06s. Furthermore, the introduction of modern static designs of dependent time overcurrent relays has enabled the margins for relay error, overshoot and safety to be reduced also.

|                                | Typical factors for standard inverse relays |              |
|--------------------------------|---------------------------------------------|--------------|
|                                | Electromechanical relay                     | Static relay |
| Relay type                     | CDG                                         | MCGG         |
| Typical basic timing error (%) | 7.5                                         | 5.0          |
| Overshoot time (s)             | 0.05                                        | 0.03         |
| Safety margin (s)              | 0.10                                        | 0.05         |

The relay basic timing error corresponds to the declared error index as defined in IEC 255-4 and BS142.

A practical solution for determining the optimum grading margin is to assume that the relay nearer to the fault has a maximum possible timing error of +2E. To this total effective error for the relay, a further 10% should be added for the overall current transformer error.

A suitable minimum grading time interval,  $t'$ , may be calculated as follows:

$$t' = \left[ \frac{2E_R + E_{CT}}{100} \right] t + t_{CB} + t_o + t_s \text{ (s)}$$

where  $E_R$  = Relay timing error to IEC 255-4 or BS142 (%)

$E_{CT}$  = Allowance for CT ratio error (%)

$t$  = Nominal operating time of relay nearer to the fault (s)

$t_{CB}$  = Circuit breaker interrupting time (s)

$t_o$  = Relay overshoot time (s)

$t_s$  = Safety margin (s)

If, for example,  $t = 0.5$  s, the time interval for an electromechanical relay tripping a conventional circuit breaker would be 0.375 s, whereas, at the lower extreme, for a static relay tripping a vacuum circuit breaker, the interval could be as low as 0.24 s.

When the overcurrent relays have independent definite time delay characteristics, it is not necessary to include the allowance for CT error.

$$\text{So } t' = \left[ \frac{2E_R}{100} \right] t + t_{CB} + t_o + t_s$$

## 9.5

### STANDARD I.D.M.T. OVERCURRENT RELAYS

Limits of accuracy have been considered by various committees and Figure 9.4 shows a typical example of the limits set by IEC255-4 and British Standards Institution Specification BS142—1983 (Section 3.2) for an inverse definite minimum time (dependent specified time) overcurrent relay.

The discriminating curves shown in Figure 9.5 illustrate the application of an overcurrent relay having 'standard inverse' operation characteristics to a sectioned radial feeder. It will be seen that with the assumed relay settings and the tolerances allowed the permissible grading margin between the overcurrent relays at each section breaker is approximately 0.5s.

With the increase in system fault current it is desirable to shorten the clearance time for faults near the power source, in order to minimize damage. It is therefore necessary to reduce the time errors, which are in this situation disproportionately large when compared with the clearance time of modern circuit breakers; this can only be achieved by improving the limits of accuracy, pick-up and overshoot. All this must be obtained without detriment to the general performance of the relay; in other words, there must be no reduction in the operating torque or weakening of the damper magnets or contact pressures, and the construction must remain simple with the minimum number of moving parts. While these requirements present considerable difficulties in manufacture, owing to variations in materials and practical tolerances, the progress made in the GEC ALSTHOM Measurements relays has made it possible to discriminate more closely by reducing the margin between both the current and the time setting of the relays on adjacent breakers.

These relays will thus enable the time setting of the relay nearest the power source to be reduced, or, alternatively, make it possible to increase the number of breakers in series without increasing the time setting of the relays at the power source.

Many of the examples in this chapter are based on electromechanical relays, such as those in the type CDG range. The techniques described also apply for static overcurrent relays such as the type MCGG shown in Figures 7.1 and 7.16.

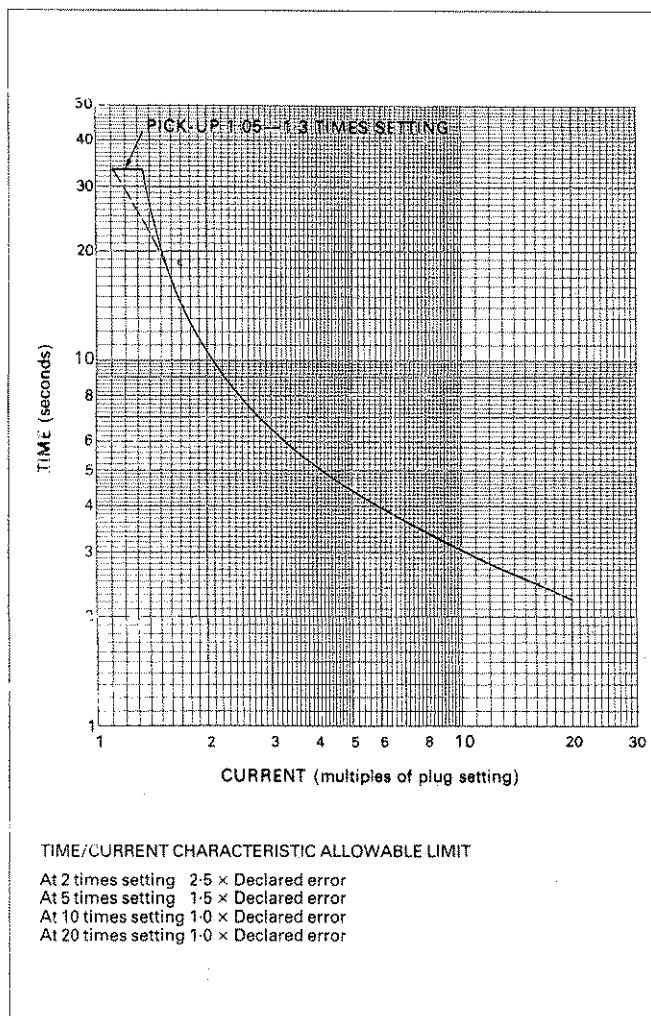


Figure 9.4 Typical limits of accuracy set by IEC 255-4 for an inverse definite minimum time overcurrent relay.

## 9.6

### COMBINED I.D.M.T. AND HIGH SET INSTANTANEOUS OVERCURRENT RELAYS.

A further advantage can be gained on long transmission lines or transformer feeders, where the source impedance is small in comparison with the protected circuit impedance, by adding a high set instantaneous overcurrent element to the inverse time overcurrent element. This makes possible a reduction in the tripping time at high fault levels, and improves the overall system grading by allowing the 'discriminating curves' behind the high set instantaneous elements to be lowered.

As shown in Figure 9.6 one of the advantages of the high set instantaneous elements is to reduce the operating time of the circuit protection by the shaded area below the 'discriminating curves' and, provided that the source impedance remains constant, it is possible to achieve high speed protection over a large section of the protected circuit.

Another important advantage that can be gained by the use of high set instantaneous elements, and which affects the system grading, is also shown in Figure 9.6, which clearly illustrates the important point that the grading with the relay immediately behind the instantaneous elements is carried out at the current setting of the instantaneous elements and not at the maximum fault level that would be required for grading standard I.D.M.T. relays. For example, in Figure 9.6 relay  $R_2$  is graded with relay  $R_3$  at 500 A and not 1100 A, allowing relay  $R_2$  to be set with a 0.15 TMS instead of 0.2 while maintaining a grading margin between relays of 0.4s. Similarly, relay  $R_1$  is graded with  $R_2$  at 1400 A and not at 2300 A.

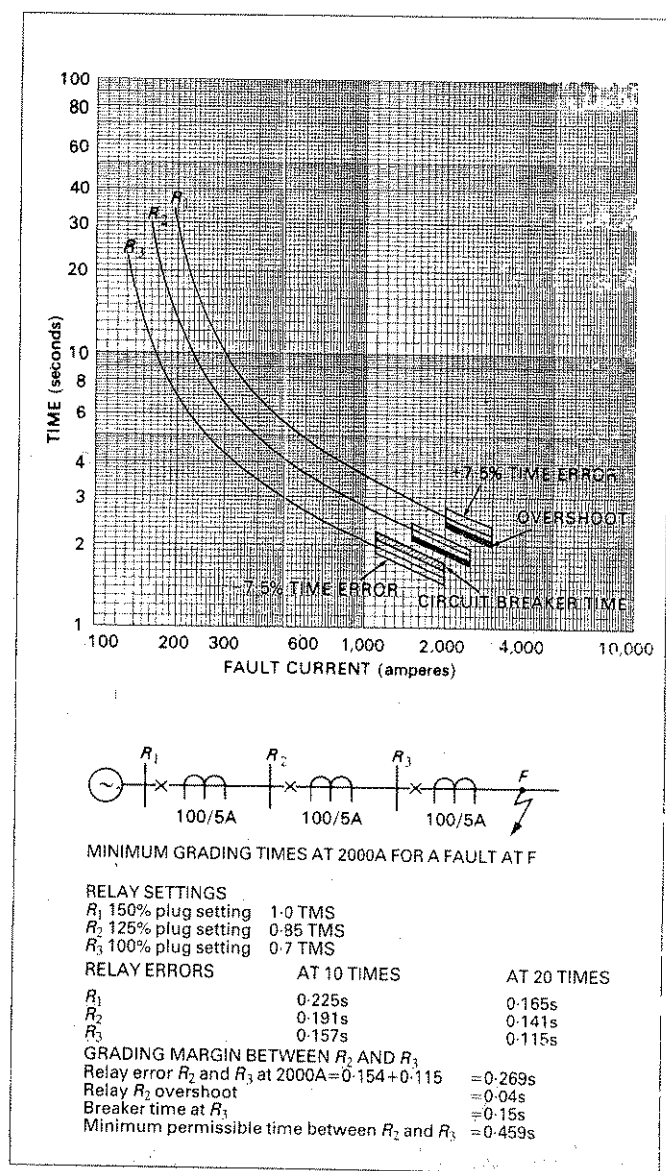


Figure 9.5 Application of an electromechanical I.D.M.T. overcurrent relay to a sectional radial feeder.

When using instantaneous overcurrent elements, care must be exercised in choosing the settings, to prevent them operating for faults beyond the protected section. The reason for this is that although the steady state r.m.s. value of the fault current for a fault at a point beyond the required reach point may be less than the relay setting, the initial current due to an offset in the current wave may be greater than the relay pick-up value and cause it to operate.

When applied to power transformers, the high set instantaneous overcurrent elements must be set above the maximum through fault current that the power transformer can supply for a fault across its LV terminals, in order to maintain discrimination with the relays on the LV side of the transformer. The limitation on the application of the high set instantaneous overcurrent relay, which is known as transient over-reach, has been reduced on the GEC ALSTHOM Measurements attracted armature relay type CAG 17 to about 3–5% depending on the line angle. Transient over-reach occurs when the current wave contains a d.c. component and is defined as:

$$\text{Percentage transient over-reach} = \frac{I_1 - I_2}{I_2} \times 100$$

where  $I_1$  = relay pick-up current in steady state r.m.s. amperes

$I_2$  = steady state r.m.s. current which when fully offset will just pick up the relay

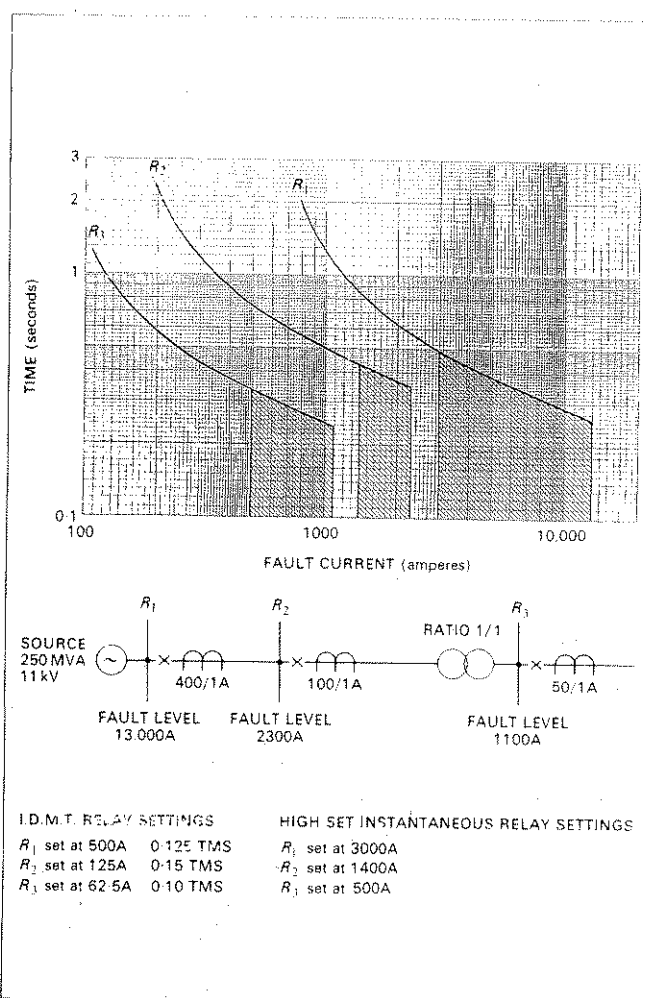


Figure 9.6 Characteristics of combined I.D.M.T. and high set instantaneous overcurrent relay.

This relay can be incorporated in the same case as an electromechanical I.D.M.T. overcurrent relay, for example type CDG11, to make a combined relay type CDG11/CAG17, without involving extra panel space or drilling.

Alternatively, if static relays are preferred, the type MCGG relay can be supplied with an instantaneous high set element, which has an even lower transient over-reach and also is capable of withstanding transformer magnetizing inrush currents. Otherwise it is applied in a similar manner.

## 9.7

### VERY INVERSE OVERCURRENT RELAYS

Very inverse overcurrent relays are particularly suitable if there is a substantial reduction of fault current as the distance from the power source increases. The characteristics of this relay are such that its operating time is approximately doubled for a reduction in current from 7 to 4 times the relay current setting. This permits the use of the same time multiplier setting for several relays in series.

In the example shown in Figure 9.7, a comparison is made between the characteristics of two types of electromechanical I.D.M.T. relays, the type CDG 11 which has standard inverse operation characteristics and the type CDG 13 with its very inverse characteristic. Fault currents at stations J, H and G are assumed to be 1225A, 700A and 400A respectively, that is, in the ratio of 7 to 4 between successive substations. All the relays are set at 0.2 TMS. It can be seen from Figure 9.7 that with the very inverse relays a margin of 0.33s in the tripping times of adjacent circuit breakers is achieved, whereas with the I.D.M.T. relays the difference is only 0.24s.

It is shown below that the grading margin of 0.33s achieved with the very inverse relays is adequate for proper



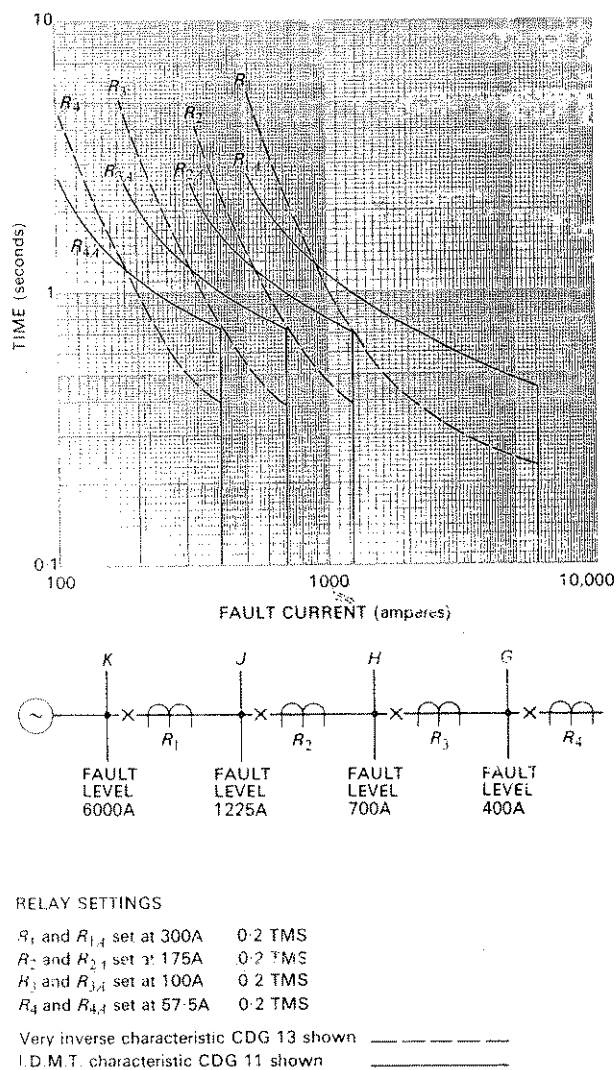


Figure 9.7 Comparison of CDG 11 and CDG 13 relay characteristics.

discrimination, whereas the time of 0.24s obtained with standard I.D.M.T. relays is insufficient for this purpose. The minimum grading margin permissible when using 0.2 TMS is given by:

$$\begin{aligned} &\text{The sum of the relay errors between} \\ &\text{adjacent relaying points estimated at a} \\ &\text{specific fault level and 0.2 TMS} \\ &+ \\ &\text{Circuit breaker operating time} \\ &+ \\ &\text{Relay overshoot} \end{aligned}$$

In the case of the very inverse time relays, this will be equal to:

$$(0.054 + 0.029) + 0.15 + 0.05 = 0.283s$$

where 0.054s is the relay error at 4 times setting and 0.2 TMS  
0.029s is the relay error at 7 times setting and 0.2 TMS  
0.15s is the circuit breaker operating time  
0.05s is the CDG 13 relay overshoot time

The actual grading margin obtained in the example shown in Figure 9.7 using very inverse relays is 0.33s, whereas the minimum permissible time for correct discrimination is 0.283s. Very inverse relays are therefore suitable.

Using standard I.D.M.T. relays, the minimum permissible time between adjacent circuit breakers will be equal to:

$$(0.0712 + 0.0525) + 0.15 + 0.04 = 0.3137s$$

where 0.712s is the relay error at 4 times setting and 0.2 TMS

0.0525s is the relay error at 7 times setting and 0.2 TMS

0.15s is the circuit breaker operating time

0.04s is the CDG 11 relay overshoot time

So the minimum permissible time for correct discrimination between adjacent circuit breakers is 0.3137s, whereas the actual difference in time between adjacent relaying points, using I.D.M.T. relays, is only 0.24s. The standard I.D.M.T. relay could not therefore be applied with the proposed TMS. This shows that the use of very inverse time relays in place of standard I.D.M.T. relays is advantageous where the fault current decreases substantially between adjacent relaying points.

It should be noted that the following assumptions have been made in the calculations:

- The relay errors between adjacent circuit breakers are assumed to be positive on one side and negative on the other.
- The decrease of overshoot time with lower values of TMS is not commensurate with the decrease in TMS, so a

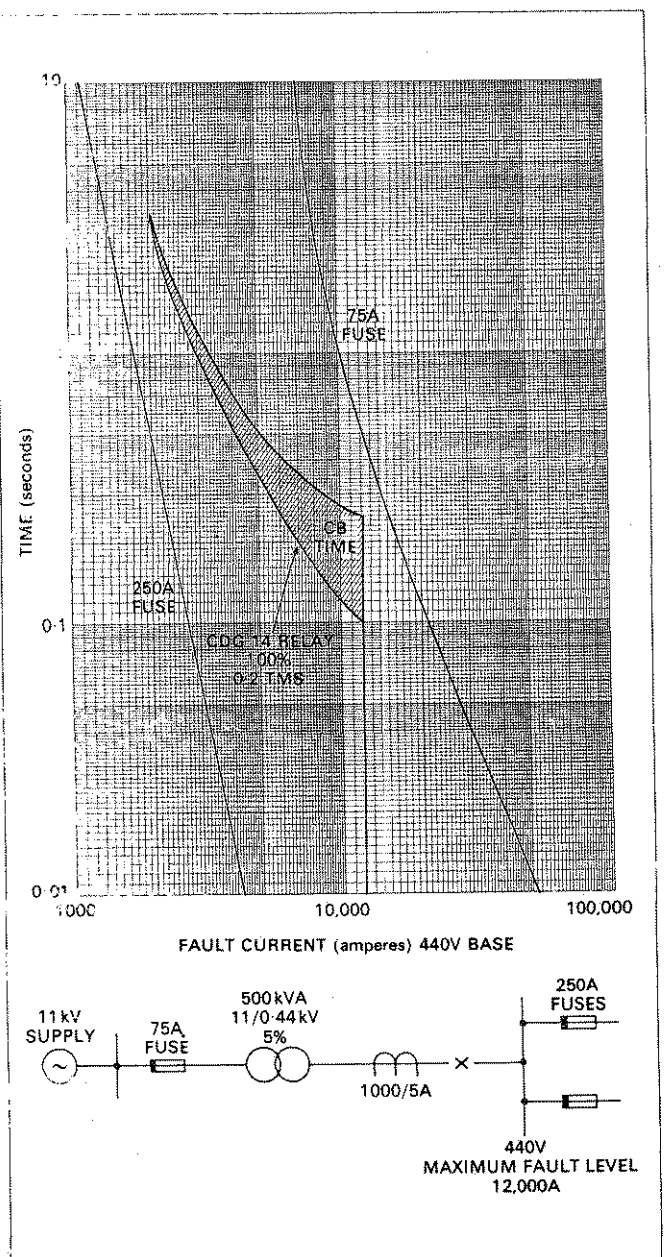
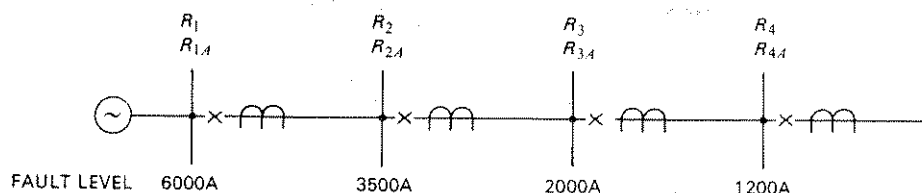
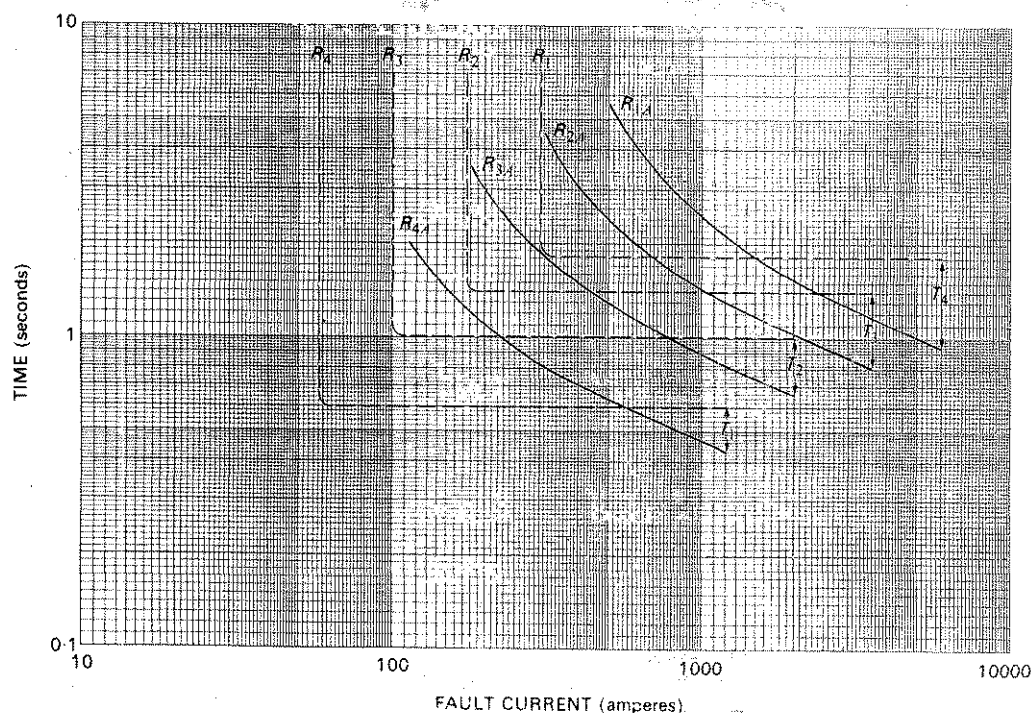


Figure 9.8 Application of CDG 14 to a distribution system supplied via an 11kV fused transformer.



# GRADING MARGIN BETWEEN RELAYS 0.4s



SETTINGS OF INDEPENDENT  
(DEFINITE) TIME RELAY (MCGG)

|                    |      |
|--------------------|------|
| $R_1$ set at 300A  | 1.8s |
| $R_2$ set at 175A  | 1.4s |
| $R_3$ set at 100A  | 1.0s |
| $R_4$ set at 57.5A | 0.6s |

SETTINGS OF I.D.M.T. RELAY (CDG11)  
WITH STANDARD INVERSE CHARACTERISTIC

|                       |         |
|-----------------------|---------|
| $R_{1A}$ set at 300A  | 0.2TMS  |
| $R_{2A}$ set at 175A  | 0.3TMS  |
| $R_{3A}$ set at 100A  | 0.37TMS |
| $R_{4A}$ set at 57.5A | 0.42TMS |

Figure 9.9 Comparison of definite time and standard I.D.M.T. relays

constant time is considered for all the time multiplier settings.

c. The relay errors are taken to be 7.5% of the actual time at the TMS used, although the GEC ALSTHOM Measurements relays have an error lower than 7.5% from 4 to 20 times the relay current setting.

The points illustrated by this example would apply in principle if the respective characteristics of the static type MCGG relay, 'SI' for standard inverse and 'VI' for very inverse, were to be used instead. However, the time margins would in general be smaller, as shown in the table in Section 9.4.5.

## 9.8 EXTREMELY INVERSE OVERCURRENT RELAYS

Other alternative relays available but having extremely inverse characteristics are the electromechanical type CDG14 and the static type MCGG again, but this time using its curve 'EI'.

In this characteristic the operation time is approximately inversely proportional to the square of the applied current. This makes it suitable for the protection of distribution feeder circuits in which the feeder is subjected to peak

currents on switching in, as would be the case on a power circuit supplying refrigerators, pumps, water heaters and so on, which remain connected even after a prolonged interruption of supply. The long time operating characteristic of the extremely inverse relay at normal peak load values of current makes this relay particularly suitable for grading with fuses. Figure 9.8 shows typical curves to illustrate the application of this relay to an 11 kV system supplying a distribution transformer via a high voltage fuse, the relay itself being located on the LV (440 V) side of the transformer.

The 'discriminating curves' for the extremely inverse relay and the 75 A (11 kV) high voltage fuse clearly indicate a difference in time of 0.4s between the operating time of the relay and the clearance time of the 75 A fuse at the maximum fault level of 12,000 A, which allows for the circuit breaker operating time, variations in the fuse operating time and relay errors. Another application of this relay is in conjunction with auto-reclosers in the low voltage distribution circuits. The majority of faults are transient in nature and unnecessary blowing and replacing of the fuses can be avoided if the auto-reclosers are set to operate before the fuse blows. If the fault persists, the auto-recloser locks itself in the closed position after one opening and the fuse blows to isolate the fault.

## 9.9

### INDEPENDENT (DEFINITE) TIME OVERCURRENT RELAYS

The static overcurrent relay type MCGG is also provided with three alternative independent or definite time characteristics, 0-2s, 0-4s and 0-8s, selectable by means of switches in the relay front plate.

These characteristics provide a ready means of co-ordinating several relays in series in situations in which the system fault current varies very widely due to changes in source impedance, as there is a relatively small change in time with the variation of fault current. The characteristics of this relay are shown in Figure 9.9, together with those of the standard I.D.M.T. relay, to indicate that an advantage is gained by the inverse relay at the higher values of fault current, whereas the definite time relay has the advantage at the lower current values.

The time difference at the maximum fault levels is indicated by the vertical lines  $T_1$ ,  $T_2$ ,  $T_3$  and  $T_4$ . While this relay can be used in a very large number of overcurrent applications, it cannot, however, replace the standard I.D.M.T. relay or the very inverse relay if it is possible to take advantage of the reduction of fault current as the distance from the power source increases.

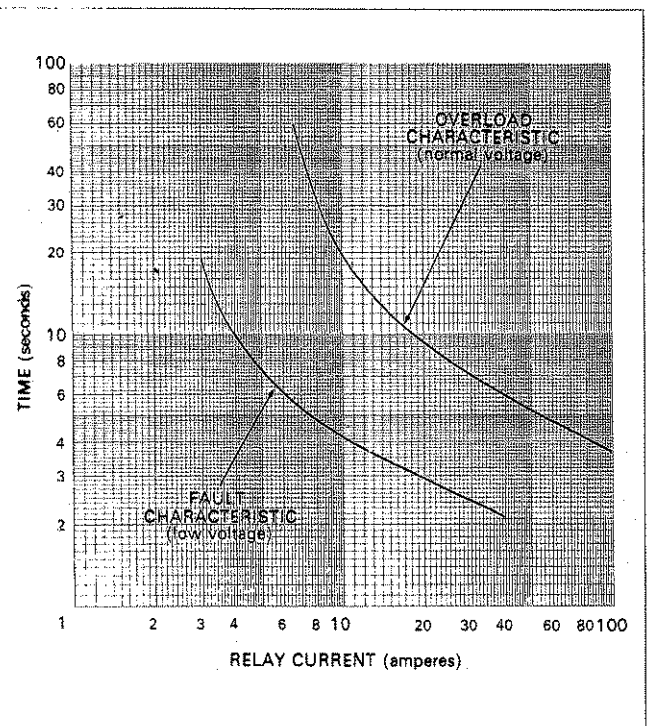


Figure 9.10 Typical time/current characteristics for a CDV 22 relay set at 100% (5 amperes) and 1.0 TMS.

## 9.10

### VOLTAGE CONTROLLED OVERCURRENT RELAYS (TYPE CDV22)

Difficulty is often experienced when applying the inverse time overcurrent relay to generators, because in many instances the generator synchronous reactance causes the sustained fault current to be lower than full load; this depends on the load conditions before the fault and on whether or not the automatic voltage regulator is in service.

Fault conditions invariably cause a greater drop in busbar voltage than normal overload, and this fact has been utilized in a voltage controlled overcurrent relay (type CDV 22) which has the following characteristics:

- The relay operates to the upper curve in Figure 9.10 under overload conditions, when the system voltage is maintained near normal. The operating times are considerably longer than the corresponding times for an I.D.M.T. relay. This is an advantage, since the thermal capacity of a generator is usually greater than is allowed by the normal I.D.M.T. relay, which is designed for feeder protection.
- The relay operates to the lower curve in Figure 9.10 under fault conditions, when the system voltage falls below a predetermined value. This curve is a standard inverse curve and is based on a setting current of 0.4 times the actual plug setting, which allows current grading to be achieved with the I.D.M.T. (dependent specified time) relays in the power system.

There are two types of CDV22 relay:

Type A for solidly earthed systems.

Type B for resistance earthed systems.

On a solidly earthed system, the voltage between phase and earth falls during phase to phase faults to approximately 50%, the earth and phase fault levels being about equal. For phase to earth faults, the voltage will drop depending on the position of the fault. If the fault is external the voltage measured may be high enough to prevent relay operation, but for close-up faults, the voltage measured will be low, allowing the under-voltage element to drop off. The type A relay has its under-voltage element connected between phase and neutral and set at 60%.

The relay is applied to solidly earthed systems and operates for both phase and earth faults.

On a resistance earthed system the earth fault current level is much lower than the phase fault level. During phase to

phase faults the phase to earth voltage falls to approximately 50%.

With phase to earth faults the voltage drops for all faults on the system no matter where they occur. If, therefore, a 60% under-voltage setting is used there will be no discrimination between earth faults on the system and close up or terminal earth faults.

So by connecting the under-voltage element of the type B relay phase-phase and giving it a lower setting of 30%, operation is prevented for earth faults but discrimination is made between faults at the generator terminals and faults elsewhere on the system.

The type B relay is therefore applied to resistor earthed systems and gives protection for phase faults only.

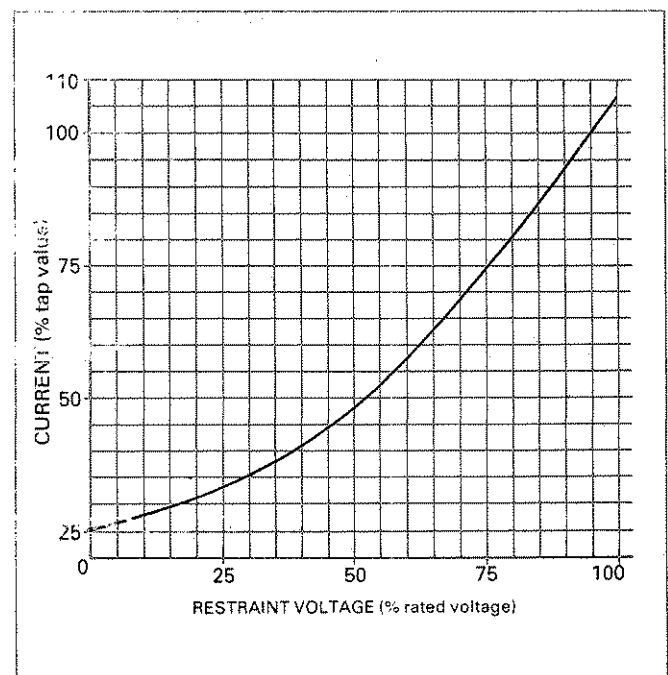


Figure 9.11 Operation characteristic of voltage restrained overcurrent relay, type CDV21, with time multiplier setting = 1.0.

### 9.11

#### VOLTAGE RESTRAINED OVERCURRENT RELAYS (TYPE CDV21)

An alternative technique is applied in the type CDV21 voltage restrained relay. The two elements of this relay are induction electromagnets arranged to provide opposing torques in a single disc rotor. One electromagnet has a 'current' winding very similar to that of a standard I.D.M.T. relay; the other has an equivalent 'restraining' winding energized from a VT connected to the generator. The effect is to provide an I.D.M.T. type of overcurrent relay with a characteristic which is modified continuously according to the voltage at the machine terminals, as shown in Figure 9.11.

Alternatively, the relay may be regarded as an impedance type with a long dependent time delay.

In consequence, the relay continues to operate more or less independently of the machine current decrement.

### 9.12

#### SUMMARY

Figure 9.12 compares the characteristics of the various electromechanical types of inverse time relays referred to in this chapter. It should, however, be noted that all these curves are shown at 1.0 TMS.

Figure 9.13 shows a relay typical of those mentioned. The simplicity of the movement will be noted, and by minor variations on this basic design the several characteristics previously described can be obtained. The relays are made in single pole or triple pole units and mounted in vertical or horizontal cases.

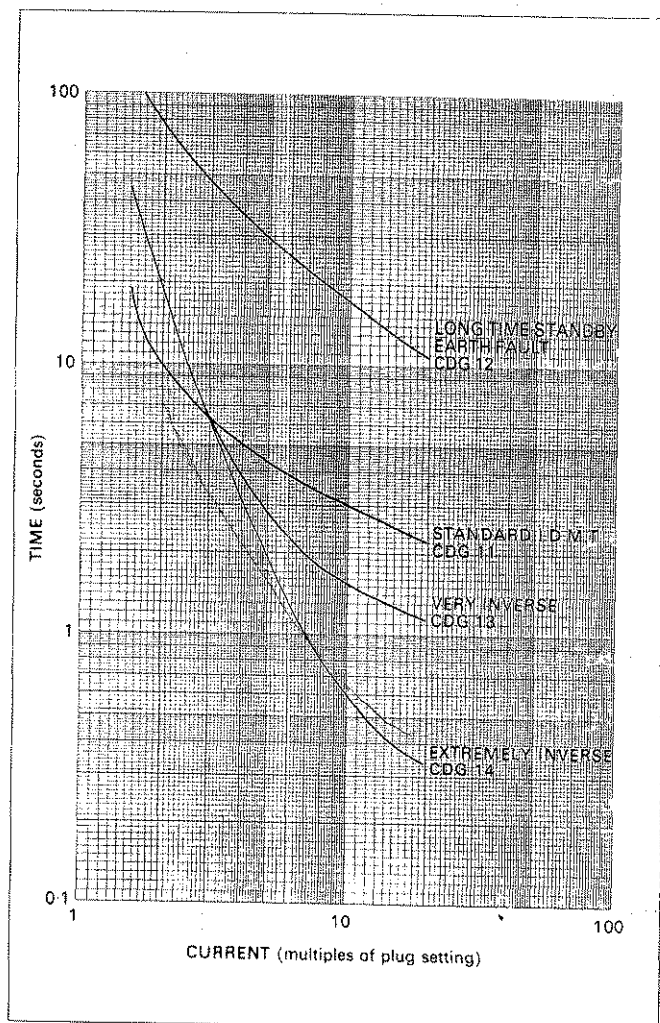


Figure 9.12 Comparison of electromechanical overcurrent relay characteristics.

Figure 9.14 illustrates that the relay can be easily withdrawn from its case, which is specially designed to simplify the testing and maintenance of the relay.

The performance of electromechanical relays is inevitably affected by mechanical considerations such as pivot friction. As these problems are not present in static designs, it has been possible to produce static overcurrent relays with operation characteristics which follow a defined theoretical inverse curve more closely over a wider range of applied current.

The following are typical operating characteristics in use:

Standard inverse 
$$t = \frac{0.14}{I^{0.02} - 1}$$

Very inverse 
$$t = \frac{13.5}{I - 1}$$

Extremely inverse 
$$t = \frac{80}{I^2 - 1}$$

Long time standby earth fault 
$$t = \frac{120}{I - 1}$$

where  $t$  = relay operating time(s)

$I$  = current (multiple of plug setting)

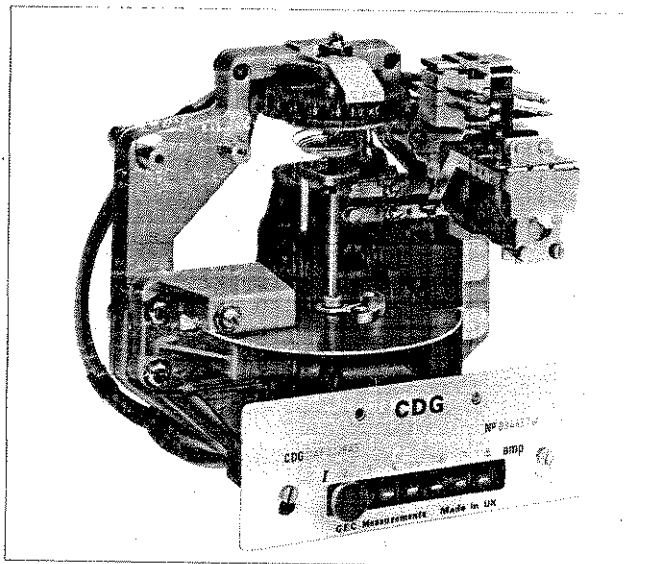


Figure 9.13 Typical induction pattern overcurrent element.

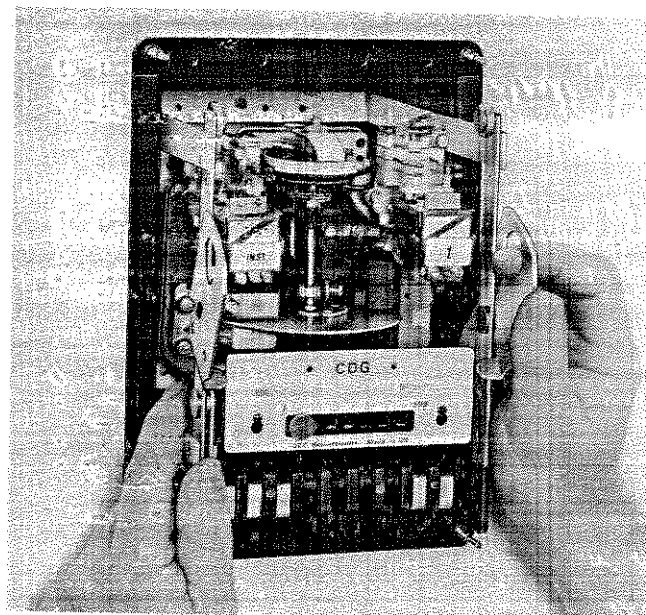


Figure 9.14 Withdrawable features of relay case to simplify testing and maintenance.

With many relay designs, a change of characteristic requires a change of relay. However the introduction of the microcomputer to overcurrent relay designs brings greater versatility, such that the MIDOS MCGG relay illustrated in Figure 7.1 gives, in one relay, the choice of the four inverse characteristics previously defined, together with three definite time ranges, all by switched selection, as shown in Figure 9.15.

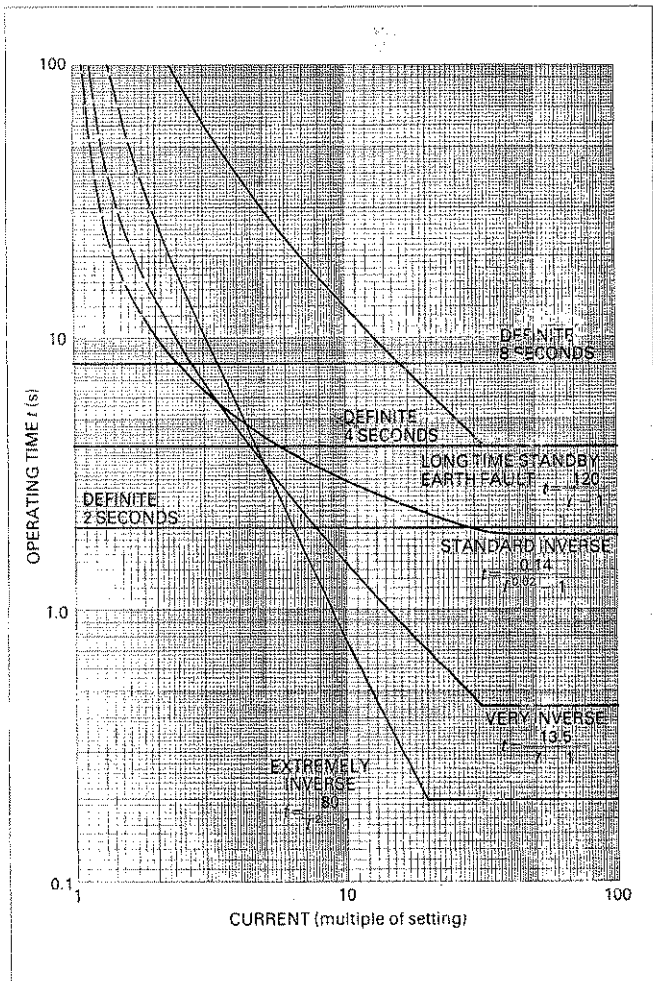


Figure 9.15 Multiple operation time/current characteristics of static overcurrent relay, type MCGG.

### 9.13 TIME/CURRENT CHARACTERISTICS

A family of typical time/current characteristic curves for a standard I.D.M.T. relay is shown in Figure 9.16. It will be seen that a curve has been plotted for each major division of the time multiplier setting, but, as the adjustment is continuous, any intermediate curve can be obtained by interpolation.

The curves are plotted in terms of multiples of the plug setting current, to enable the same curve to be used regardless of which plug setting is used. This is made possible by the fact that the plug setting bridge which determines the pick-up value of the relay selects taps on the operating coil and the number of pick-up ampere-turns per tap is constant.

It should be noted that the characteristics of the relay are not shown for low multiples of the relay plug setting current. This is because the operating torque on a relay at very low values may be reduced to the point where any unwanted friction may affect relay operation and will slow down the relay.

The value of the time/current characteristic is that it can be used to estimate how long the relay will take to close its contacts for any value of the time multiplier setting, provided that the level of the actuating current is known.

### 9.14 PHASE FAULT OVERCURRENT PROTECTION OF DELTA/STAR TRANSFORMERS

Whether two or three overcurrent elements should be used depends on the current distribution for a phase to phase fault on the star side of the power transformer and the minimum fault current available for operation of the relay. If the ratio between the minimum fault current and full load is greater than four, two overcurrent elements can be used, but the operating time of the relay may be slower according to which phases on the star side are involved in the fault.

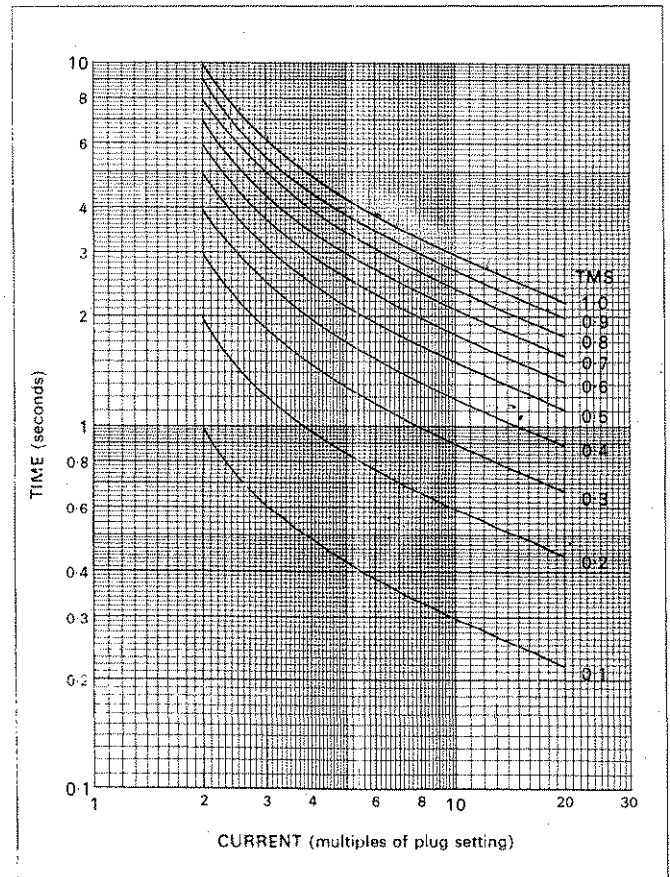


Figure 9.16 Typical time/current characteristics of 3 seconds standard electromechanical I.D.M.T. relay.

Also, unless there is additional current infeed into the LV current transformers which is not seen by the HV current transformers, care has to be exercised to ensure that proper discrimination between the LV and HV sides is not affected by the fact that, for three-phase faults both the LV and the HV relays see the same current, but for a phase-phase fault the HV relay sees the full three-phase fault current, whereas the LV relay sees 0.866 of the three-phase fault current.

### 9.15 CALCULATION OF PHASE FAULT OVERCURRENT RELAY SETTINGS

The correct co-ordination of overcurrent relays in a power system requires the calculation and plotting, on a suitable log-log paper, of the estimated relay settings, in terms of both current and time, in order to ensure that a suitable grading margin between the relays at adjacent substations exists to provide the desired discrimination.

#### 9.15.1 Independent (definite) time relays

The selection of settings for independent time relays

| Location | Total impedance (ohms) |         | Fault current (A) |         | Maximum load current (A) | CT ratio | Relay current setting |                     |
|----------|------------------------|---------|-------------------|---------|--------------------------|----------|-----------------------|---------------------|
|          | Minimum                | Maximum | Maximum           | Minimum |                          |          | Per cent              | Primary current (A) |
| G        | 0.81                   | 1.62    | 7850 ✓            | 3920 ✓  | 420                      | 400/5A   | 150                   | 600                 |
| H        | 1.41                   | 2.22    | 4500 ✓            | 2860 ✓  | 300                      | 400/5A   | 125                   | 500                 |
| J        | 2.36                   | 3.17    | 2690 ✓            | 2003 ✓  | 130                      | 200/5A   | 100                   | 200                 |
| K        | 4.56                   | 5.37    | 1395 ✓            | 1182 ✓  | 50                       | 100/5A   | 100                   | 100                 |

Table 9.1 System data for Figure 9.17

| Relay at | Fault location |                |       |                |       |                |       |                |     |                |       |                |       |                |       |                |
|----------|----------------|----------------|-------|----------------|-------|----------------|-------|----------------|-----|----------------|-------|----------------|-------|----------------|-------|----------------|
|          | K              |                |       |                | J     |                |       |                | H   |                |       |                | G     |                |       |                |
|          | PSM            | T <sub>c</sub> | TMS   | T <sub>a</sub> | PSM   | T <sub>c</sub> | TMS   | T <sub>a</sub> | PSM | T <sub>c</sub> | TMS   | T <sub>a</sub> | PSM   | T <sub>c</sub> | TMS   | T <sub>a</sub> |
| K        | 13.95          | 2.6            | 0.05  | 0.13           |       |                |       |                |     |                |       |                |       |                |       |                |
| J        | 6.975          | 3.6            | 0.175 | 0.63           | 13.45 | 2.6            | 0.175 | 0.455          |     |                |       |                |       |                |       |                |
| H        |                |                |       |                | 5.38  | 4.1            | 0.233 | 0.955          | 9   | 3.15           | 0.233 | 0.735          |       |                |       |                |
| G        |                |                |       |                |       |                |       |                | 7.5 | 3.45           | 0.358 | 1.235          | 13.08 | 2.65           | 0.358 | 0.95           |

PSM = Relay plug setting multiplier  
 T<sub>c</sub> = Relay operating time from standard curve at given PSM(s)  
 TMS = Relay time multiplier setting  
 T<sub>a</sub> = Relay actual operating time(s)

Table 9.2 Relay time setting calculation

presents little difficulty. The overcurrent elements must be given settings which are lower, by a reasonable margin, than the fault current which is likely to flow to a fault at the remote end of the system up to which back-up protection is required, with the minimum plant in service. The settings must be high enough to avoid relay operation with the maximum probable load, a suitable margin being allowed for large motor starting currents or transformer inrush transients. Time settings will be chosen to allow suitable grading margins, as discussed in Section 9.4.

### 9.15.2 Inverse time relays

When the power system consists of a series of short sections of cable, so that the total line impedance is low, the value of fault current will be controlled principally by the impedance of transformers or other fixed plant and will not vary greatly with the location of the fault. In such cases, it may be possible to grade the inverse time relays in very much the same way as definite time relays. However, when the prospective fault current varies substantially with the location of the fault, it is possible to make use of this fact by employing both current and time grading so as to improve the overall performance of the relay.

This is one of the main advantages of the inverse time relay over the definite time relay on systems in which there is a large variation in fault current between the two ends of the feeder, because faster operating times can be achieved by the relays nearest to the source, where the fault level is the highest.

The overcurrent relay grading calculations are best set out in tabular form and the distribution system shown in Figure 9.17 will be used to illustrate the method. In this example, the 11 kV substation G busbars are fed via two grid transformers, which are connected to an EHV system of negligible source impedance. Thus the short-circuit power on the 11 kV busbars at substation G with the two grid transformers in service is 150 MVA, which corresponds to a source impedance of 0.81 ohms.

The supply substation G is shown feeding substations H, J, K and L through a radial distribution system that includes a feeder section having the phase impedances shown in the diagram.

Loads are supplied from each substation, the summated

load currents flowing in the feeder circuits being as shown. The data are analyzed in Table 9.1. The total impedance, including the source impedance, from the source to each

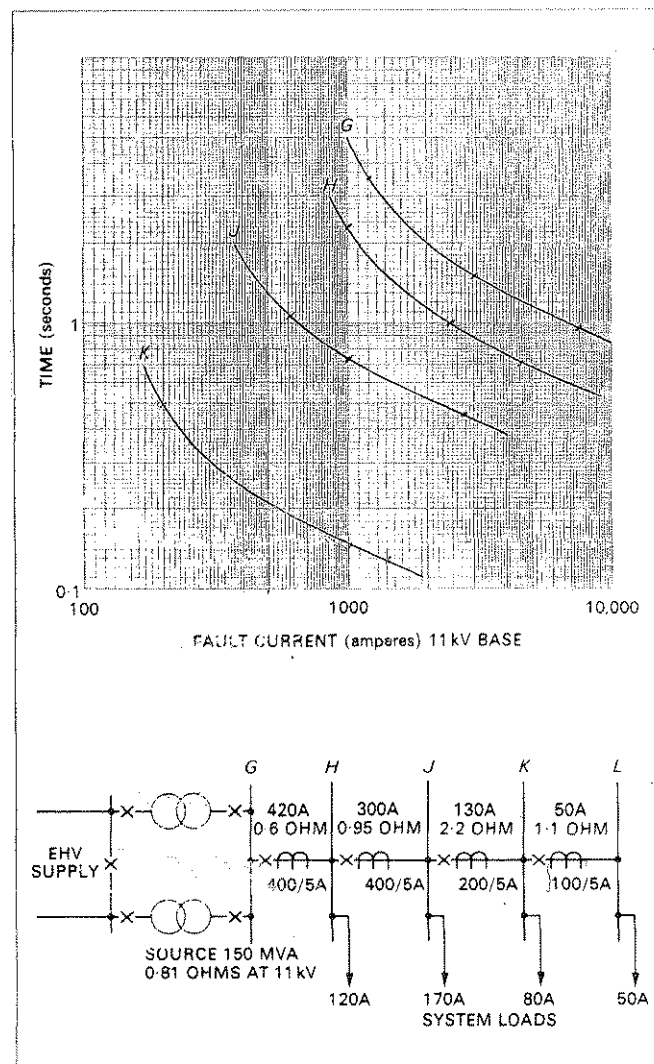


Figure 9.17 11 kV radial distribution system.



substation is given in the second column; the third column gives the corresponding impedances with the busbar short-circuit power at substation *G* reduced to an assumed minimum, in this example by disconnecting one of the two supply transformers. The fourth and fifth columns contain the corresponding maximum and minimum fault currents.

The maximum load currents transmitted through each substation into the next feeder section are listed in the sixth column. From these data, suitable current transformer ratios and overcurrent relay settings are selected. It should be noted that the primary current setting should be safely above the maximum estimated load current, in order to allow some margin for load growth, unexpected high loads, transient peak loads and the complete resetting of the relay after through faults, with the circuit carrying the maximum prospective load current. The relay settings must be well below the minimum fault current in the fifth column.

Overcurrent relays are intended to provide a discriminative protection against system faults, and do not give precise overload protection. Nevertheless, the measure of overload protection which is obtained is often thought to be of value in protecting cables against abnormal loading. It is for this reason that the primary relay settings are not usually made as high as would be possible if only fault currents were considered. Once the relay current settings have been chosen, the relay time multiplier settings are calculated as set out in Table 9.2. The grading is calculated for the maximum relevant values of fault current, which, because of the 'inverse' shape of the relay characteristic curve, ensures that the grading margin will be correspondingly increased for any lower value of current. Starting with the relay in substation *K* farthest from the power source, the relay plug setting multiplier is calculated from a knowledge of the maximum fault current flowing through this point and the relay current setting.

#### Substation *K*

CT ratio 100/5A

Relay CDG 11 (standard I.D.M.T.) current setting

= 100%

= 100 A

Maximum fault level at substation *K* busbars

= 1395 A

$$\text{Therefore relay PSM} = \frac{1395}{100} = 13.95$$

Now, from Figure 9.4, the operating time of the standard I.D.M.T. relay at 13.95 times the relay plug setting and 1.0 TMS is 2.6 seconds. No relay follows *K*, but a small time delay is still required to permit discrimination with the lower voltage system protection. Furthermore, the contact travel of relay *K* should not be made unduly small, so as to avoid the possibility of operation by mechanical shock.

A time multiplier setting of 0.05 is as low as is wise in this latter respect and is adopted in this example, assuming that discrimination with lower voltage switchgear is satisfactory. Hence, an actual tripping time for relay *K* is obtained:

$$0.05 \times 2.6 = 0.13 \text{ s}$$

A grading margin of 0.5 s is adopted in this example, so that the relay at substation *J* should have an operating time, for a fault at substation *K*, as follows:

#### Substation *J*

CT ratio 200/5A

Relay CDG 11 (standard I.D.M.T.) current setting

= 100%

= 200 A

Maximum fault level for grading relay *J* with *K*  
= 1395 A

$$\text{Therefore relay PSM} = \frac{1395}{200} = 6.975$$

Now, from Figure 9.4, the operating time of the standard I.D.M.T. relay at 6.975 times the relay plug setting and 1.0 TMS is 3.6 seconds.

$$\begin{aligned} \text{Required relay discriminating time} &= 0.13 + 0.5 \\ &= 0.63 \text{ s} \end{aligned}$$

$$\text{Therefore required relay TMS} = \frac{0.63}{3.6} = 0.175$$

The calculations now proceed for relay *J* with a close-up fault at substation *J* giving a plug setting multiplier that is calculated as follows:

Maximum fault current for a fault just outside substation *J* busbars = 2690 A

$$\text{Therefore relay PSM} = \frac{2690}{200} = 13.45$$

Now, from Figure 9.4, the operating time of the standard relay at 13.45 times the relay plug setting is 2.6 seconds, which, in conjunction with the TMS previously determined for relay *J* as 0.175, gives an actual relay *J* operating time for a close-up fault, at maximum fault level, of:

$$0.175 \times 2.6 = 0.455 \text{ s}$$

The grading of the remaining relays proceeds by stages similar to those set out above.

It is appreciated that some of the values set out in Table 9.2 are shown to a higher order of accuracy than is justified in practice; this is desirable in this theoretical example in order that trends in the grading figures will not be confused by approximations. It will be noted that although the tripping times increase in sequence from relay *K* to *G*, the operating time of relay *G* for a close-up fault is much less than three grading steps greater than that of relay *K*, a gain in overall performance which is due to the inverse time/current characteristic of the relay.

Finally, to complete the exercise, the discriminating curves for the relays in substations *G*, *H*, *J* and *K* are plotted in Figure 9.17, from which it can clearly be seen that, at the maximum fault levels at the various substation busbars, a grading margin of 0.5 s has been achieved and that the relays will also operate satisfactorily with the minimum fault current available.

### 9.16

#### EARTH FAULT PROTECTION

In the foregoing description, attention has been principally directed towards phase fault overcurrent protection. More sensitive protection against earth faults can be obtained by using a relay which responds only to the residual current of the system, since a residual component exists only when fault current flows to earth. The earth fault relay is therefore completely unaffected by load currents, whether balanced or not, and can be given a setting which is limited only by the design of the equipment. This statement, however, should be taken with reservations if settings of only a few per cent of system rating are considered, since unbalanced leakage or capacitance currents to earth may produce a residual quantity of this order.

On the whole, the low settings permissible for earth fault relays are very useful, as earth faults are not only by far the most frequent of all faults, but may be limited in magnitude by the neutral earthing impedance, or by earth contact resistance. The residual component is extracted by connecting the line current transformers in parallel as shown in Figure 9.18.

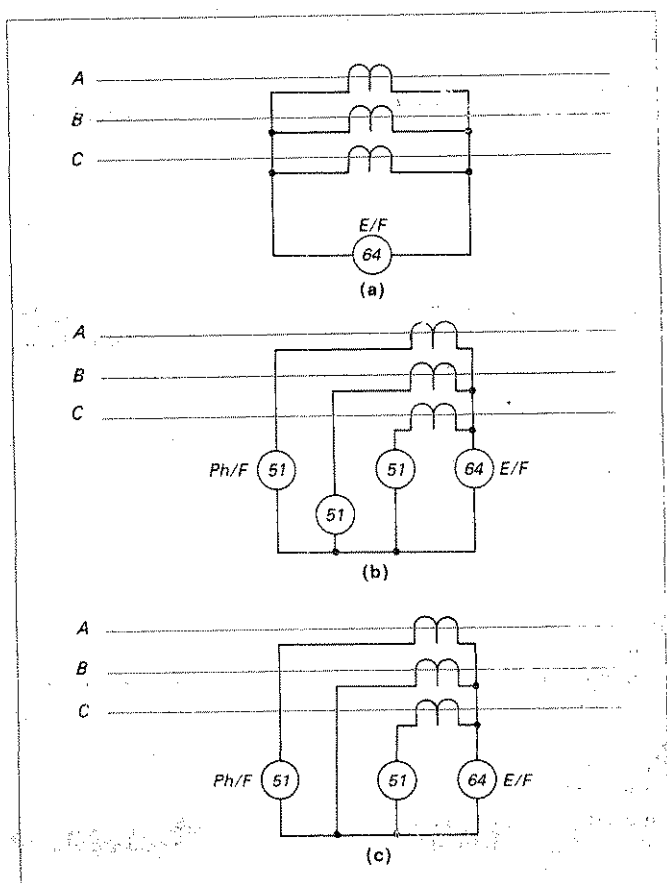


Figure 9.18 Residual connection of current transformers to earth fault relays.

The simple connection shown in Figure 9.18(a) can be extended by connecting overcurrent elements in the individual phase leads, as illustrated in Figure 9.18(b), and inserting the earth fault relay between the star points of the relay group and the current transformers.

Phase fault overcurrent relays are often provided on only two phases since these will detect any interphase fault; the connections to the earth fault relay are unaffected by this consideration. The arrangement is illustrated in Figure 9.18(c).

### 9.16.1

#### Effective setting of earth fault relays

The primary setting of an overcurrent relay can usually be taken as the relay setting multiplied by the CT ratio. The CT can be assumed to maintain a sufficiently accurate ratio so that, expressed as a percentage of rated current, the primary setting will be directly proportional to the relay setting.

When static relays are used the relatively low value and limited variation of the relay burden over the relay setting range, may result in the above holding true for the earth fault element as well. However, when using an electro-mechanical relay the earth fault element generally will be similar to the phase elements, having a similar VA consumption at setting, but will impose a far higher burden at nominal or rated current, because of its lower setting. For example, a relay with a setting of 20% will have an impedance of 25 times that of a similar element with a setting of 100%. Very frequently this burden will exceed the rated burden of the current transformers. It might be thought that correspondingly larger current transformers should be used, but this is considered to be unnecessary, since the current transformers which handle the phase burdens can operate the earth fault relay and the increased errors can easily be allowed for.

Not only is the exciting current of the energizing current transformer proportionately high due to the large burden of

the earth fault relay, but the voltage drop on this relay is impressed on the other current transformers of the paralleled group, whether they are carrying primary current or not.

The total exciting current is therefore the product of the loss of one CT and the number of current transformers in parallel. The summated magnetizing loss can be appreciable in comparison with the operating current of the relay, and in extreme cases where the setting current is low or the current transformers are of low performance, may even exceed the output to the relay. The 'effective setting current' in secondary terms is the sum of the relay setting current and the total excitation loss. Strictly speaking, the effective setting is the vector sum of the relay setting current and the total exciting current, but, for electromechanical relays at least, the arithmetic sum is near enough, because of the similarity of power factors. It is instructive to calculate the effective setting for a range of setting values of a relay, a process which is set out in Table 9.3, with the results illustrated in Figure 9.19.

| Relay ph-g setting |             | Coil voltage at setting (V) | Exciting current $I_e$ | $3I_e$ | Effective setting |      |
|--------------------|-------------|-----------------------------|------------------------|--------|-------------------|------|
| %                  | Current (A) |                             |                        |        | Current (A)       | %    |
| 5                  | 0.25        | 12                          | 0.583                  | 1.75   | 2.0               | 40   |
| 10                 | 0.5         | 6                           | 0.405                  | 1.215  | 1.715             | 34.3 |
| 15                 | 0.75        | 4                           | 0.3                    | 0.9    | 1.65              | 33   |
| 20                 | 1.0         | 3                           | 0.27                   | 0.81   | 1.81              | 36   |
| 40                 | 2.0         | 1.5                         | 0.17                   | 0.51   | 2.51              | 50   |
| 60                 | 3.0         | 1.0                         | 0.12                   | 0.36   | 3.36              | 67   |
| 80                 | 4.0         | 0.75                        | 0.1                    | 0.3    | 4.3               | 86   |
| 100                | 5.0         | 0.6                         | 0.08                   | 0.24   | 5.24              | 105  |

Table 9.3 Calculation of effective settings

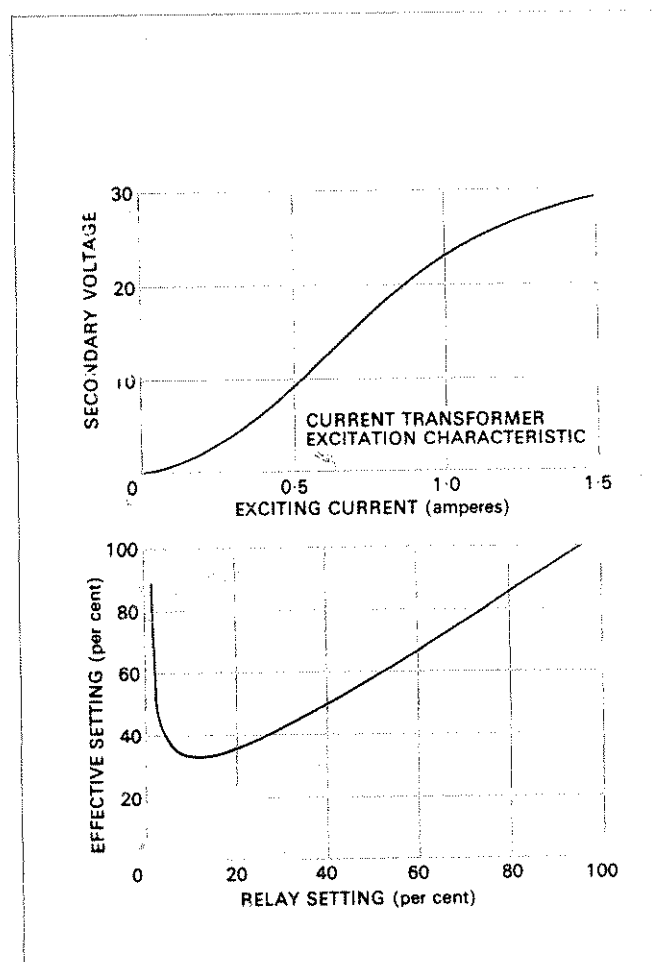


Figure 9.19 Effective setting of earth fault relay.

### 9.16.2

#### Example of typical electromechanical earth fault relay

Current transformers:

Ratio 300/5A

Knee-point voltage 30 volts

Exciting current at knee-point 1.5 A

Relay burden at setting 3 VA

It will be seen that the optimum relay setting in the above example is 13%, but very little increase in effective setting occurs up to a relay setting of 20%. It may be thought to be desirable to apply relays having a setting range of, say, 10%–40%, the optimum setting being determined by test before commissioning. It should be remembered, however, that unless the maximum earth fault current is limited by neutral earthing impedance, the relays may be subjected to a high current, especially if the current transformers have a high value of saturation e.m.f. In such cases the relay may experience considerable heating during severe system faults. The lower the tap setting, the higher the resistance of the coil winding, so the heating on lower setting taps is correspondingly higher. In this respect, a tap setting of, say, 20% is not the same when obtained from the 10%–40% range as when obtained from the 20%–80% range. The former corresponds to a winding having twice the number of turns of the latter and hence a smaller wire size. When the 20% tap is selected from the 10%–40% range, only half the coil is in use and the coil resistance is greater than would be the case if the same setting were obtained from the 20%–80% range, when the whole coil would be in service.

The higher setting range is suitable for the majority of applications and should be used unless it is known that service conditions are such that lower settings are necessary. When the fault current is limited sufficiently by neutral earthing resistance, the lower range of settings will be permissible, although frequently not necessary. In territories where the earth resistance may be so high that greater sensitivities are needed, lower settings should be applied and current transformers having sufficiently low exciting currents must be used. It is then necessary to consider the maximum earth fault current that may flow taking all possible contingencies into account, and to consider whether it is necessary to design the current transformers to limit the maximum output current by saturation.

### 9.16.3

#### Time grading of earth fault relays

The time grading of earth fault relays can be arranged in the same manner as for phase fault relays. The time/primary current characteristic cannot be kept proportionate to the relay characteristic with anything like the accuracy that is possible for phase fault relays. As has previously been shown, the ratio error of the current transformers at relay setting current may be very high. The effect of the relatively high relay impedance and the summation of CT excitation losses in the residual circuit is augmented still further by the fact that, at setting, the flux density in the current transformers corresponds to the bottom bend of the excitation characteristic. The exciting impedance under this condition is relatively low, causing the ratio error to be high. The current transformer actually improves in performance with increased primary current, while the relay impedance decreases until, with an input current several times greater than the primary setting, the multiple of setting current in the relay is appreciably higher than the multiple of primary setting current which is applied to the primary circuit, causing the relay operating time to be shorter than might be expected.

At still higher input currents, the CT performance falls off until finally the output current ceases to increase substantially. Beyond this value of input current, operation is further complicated by distortion of the output current waveform.

It is clear that time grading of earth fault relays is not such a simple matter as the procedure adopted for phase relays in Table 9.2. Either the above factors must be taken into account and the errors calculated for each current level, making the process much more tedious, or longer grading margins must be allowed.

### 9.16.4

#### Sensitive earth fault protection

In some territories, the resistivity of the earth path may be very high due to the extreme dryness and the nature of the ground itself. A system fault to earth not involving earth conductors may result in the flow of only a small current, insufficient to operate a normal protective system. A similar difficulty has arisen in the case of broken line conductors, which, after falling on to hedges or on to dry metalled roads, have remained energized because of the low leakage current and presented a danger to life.

To overcome this hazard it is necessary to provide an earth fault protective system with a setting which is considerably better than the normal line protection. To achieve this object, the relay must not only have a very low current setting, but also a low basic burden; as was seen on Figure 9.19, a low current setting for a normal relay can mean a uselessly high 'effective setting'.

Relays have been designed to meet the above stringent requirements, using a sensitive polarized element type CMU21 or static relays type CTU15B or MIDOS relay type MCSU. The CMU21 relay has a setting of 2% or 3% with a burden of 0.0065 VA at setting, or 2.5VA at rated current. The static design type CTU15B provides a setting range of 1 to 16% of rated current, with a burden of the same order, 0.005–0.012 VA at setting depending on the setting used.

The MIDOS relay MCSU has a setting range of 0.5% to 15% and a burden for a 1A rated relay of only 0.001 VA maximum at any setting. These burdens are so low that the relays can usually be energized by the same current transformers used for the conventional circuit protection. It is clear that earth fault protection having such a low setting cannot be graded with other systems, and is therefore confined to a supplementary role by the use of a long time delay, adjustable up to 10 or 15 seconds. Although grading with other system protection is not practicable, sensitive earth fault relays can be arranged to form an independently graded system providing several discriminative stages.

Transient spill current from the residually connected current transformers can be expected to exceed the relay setting during phase faults but unwanted functioning is prevented by the relatively long time delay.

The application of the relay is limited by the normal residual current that may flow during healthy conditions. Such residual effects can arise out of primary causes such as unbalanced leakage or capacitance, or can be secondary spill current from the current transformers under normal system load conditions. The value of such steady residual current is measured on site and the relay is set to the lowest value that avoids steady state operation and which will also ensure resetting after transient operation of the current measuring element. The time delay is set to exceed the longest likely operating time of the short circuit protection and the time settings of successive relays may be arranged in a graded sequence.

### 9.17

#### CO-ORDINATION WITH FUSES

The operating time of a fuse is a function of both the pre-arcing and arcing time of the fusing element, which follows an  $I^2t$  law. So, to achieve proper co-ordination between two fuses in series, it is necessary to ensure that the total  $I^2t$  taken by the smaller fuse is not greater than the pre-arcing  $I^2t$  value of the larger fuse. It has been



established by tests that satisfactory grading between the two fuses will generally be achieved if the current rating ratio between them is greater than two.

As far as the practice of grading inverse time relays with fuses is concerned, the basic approach should be, whenever possible, to ensure that the relay backs up the fuse and not vice versa, since it is very difficult to maintain correct discrimination at high values of fault current because of the fast operation of the fuse.

The relay characteristic best suited for this co-ordination with fuses is normally that of the extremely inverse relay which follows a similar  $I^2t$  characteristic. When applied, it is necessary to bear in mind that, for satisfactory co-ordination between the relay and the fuse, the primary current setting of the relay should be approximately three times the current rating of the fuse and that the grading margin for proper co-ordination, when expressed as a fixed quantity, should not be less than 0.4s or, when expressed as a variable quantity, should have a minimum value of:

$$t' = 0.4t + 0.15$$

where  $t$  = nominal operating time of fuse.

### 9.18 DIRECTIONAL PHASE FAULT OVERCURRENT RELAYS

When fault current can flow in both directions through the relay location, it is necessary to make the response of the relay directional by the introduction of directional control elements. These are basically power measuring devices in which the system voltage is used as a reference for establishing the relative direction or phase of the fault current; see Section 6.8.2 for design particulars.

Although power measuring devices in principle, they are not arranged to respond to the actual system power for a number of reasons:

i. The power system, apart from loads, is reactive, so that the fault power factor is usually low. A relay responding purely to the active component would not develop a high torque and might be much slower and less decisive than it could be.

ii. The system voltage must collapse at the point of short circuit. When the fault is single-phase, it is the particular voltage across the short-circuited points which is reduced. So a  $B-C$  phase fault will cause the  $B$  and  $C$  phase voltage vectors to move together, the locus of their ends being the original line  $bc$  for a homogeneous system, as shown in Figure 9.20.

At the point of fault the vectors will coincide, leaving zero voltage across the fault, but the fault voltage to earth will be half the initial phase to neutral voltage. At other points in the system the vector displacement will be less, but relays located at such points will receive voltages which are unbalanced in their value and phase position.

The effect of the large unbalance in currents and voltages is to make the torques developed by the different phase elements vary widely and even differ in sign if the quantities applied to the relay are not chosen carefully. To this end, each phase of the relay is polarized with a voltage which will not be reduced excessively except by close three-phase faults, and which will remain in a satisfactory relationship to the current under all conditions.

#### 9.18.1 Relay connections

This is the arrangement whereby suitable current and voltage quantities are applied to the relay. The various connections are dependent on the phase angle, at unity system power factor, by which the current and voltage applied to the relay are displaced.

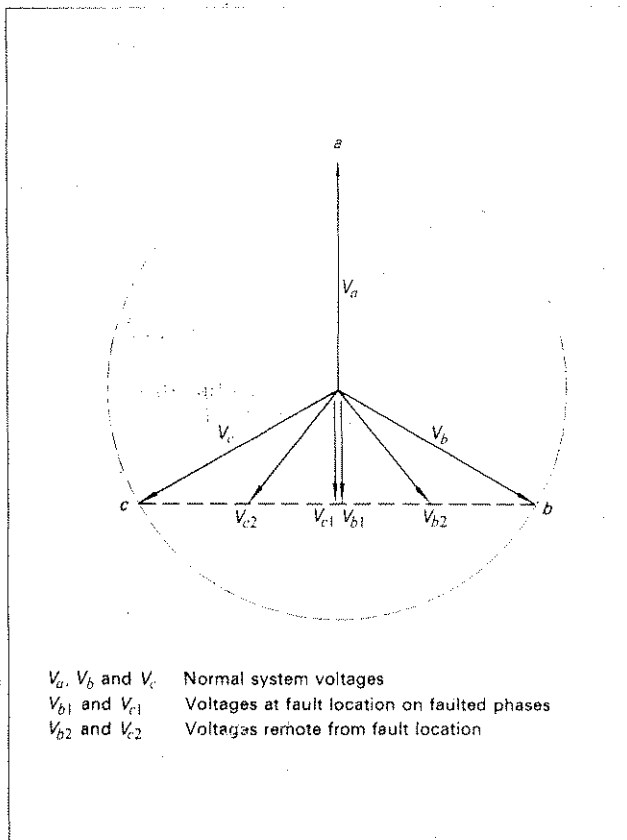


Figure 9.20 Phase voltages for a  $B-C$  fault.

#### 9.18.2 Relay maximum torque

For electromechanical relays the maximum torque angle (MTA) is defined as the angle by which the current applied to the relay must be displaced from the voltage applied to the relay to produce maximum torque. Although the relay element may be inherently wattmetric, its characteristic can be varied by the addition of phase shifting components to give maximum torque at the required phase angle.

For static relays, in which torque is not strictly relevant, the effective MTA is the angle of maximum sensitivity.

A number of different connections have been used and these are discussed below. Examination of the suitability of each arrangement involves determining the limiting conditions of the voltage and current applied to each phase element of the relay, for all fault conditions, taking into account the possible range of source and line impedances. For a full treatment of this subject, refer to 'A Study of Directional Element Connections for Phase Relays' by W. K. Sonnemann, Transactions A.I.E.E. 1950.

#### 9.18.3 30° relay connection (0° MTA)

The  $A$  phase relay is supplied with current  $I_a$  and voltage  $V_{ac}$ . In this case, the flux due to the voltage coil lags the applied  $V_{ac}$  voltage by  $90^\circ$ , so the maximum torque occurs when the current lags the system phase to neutral voltage by  $30^\circ$ . For unity power factor and 0.5 lagging power factor the maximum torque available is 0.866 of maximum. Also, the potential coil voltage lags the current in the current coil by  $30^\circ$  and gives a tripping zone from  $60^\circ$  leading to  $120^\circ$  lagging currents, as shown in Figure 9.21(a).

The most satisfactory maximum torque angle for this connection, that ensures correct operation when used for the protection of plain feeders, is  $0^\circ$ , and it can be shown that a directional element having this connection and  $0^\circ$  MTA will provide correct discrimination for all types of faults, when applied to plain feeders.



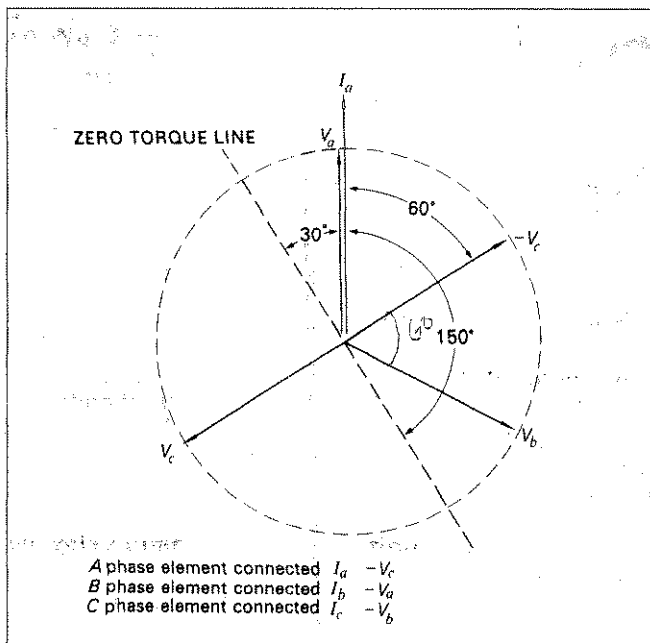


Figure 9.23 Vector diagram for the 60° No. 2 connection (phase A element).

#### 9.18.5 60° No. 2 connection (0° MTA)

The A phase relay is supplied with current  $I_a$  and voltage  $-V_c$ . In this case, the flux of the voltage coil lags the applied voltage by 90°, so the maximum torque is produced when the current lags the system phase to neutral voltage by 60°. This connection gives a correct directional tripping zone over the current range of 30° leading to 150° lagging. The relay torque at unity power factor is 0.5 of the relay maximum torque and at zero power factor lagging 0.866; see Figure 9.23.

The most suitable maximum torque angle for a directional element using this connection is 0°. However, even if this maximum torque angle is used, there is a risk of incorrect operation for all types of faults with the exception of three-phase faults. For this reason, the 60° No. 2 connection is now never recommended.

#### 9.18.6 90° relay quadrature connection

This is the standard connection for the type CDD relay; depending on the angle by which the applied voltage is shifted to produce the relay maximum torque angle, two types are available.

##### 90°–30° characteristic (30° MTA)

The A phase relay is supplied with  $I_a$  current and  $V_{bc}$  voltage displaced by 30° in an anti-clockwise direction. In this case, the flux due to the voltage coil lags the applied voltage  $V_{bc}$  by 60°, and the relay maximum torque is produced when the current lags the system phase to neutral voltage by 60°. This connection gives a correct directional tripping zone over the current range of 30° leading to 150° lagging; see Figure 9.24. The relay torque at unity power factor is 0.5 of the relay maximum torque and at zero power factor lagging 0.866. A relay designed for quadrature connection and having a maximum torque angle of 30° is recommended when the relay is used for the protection of plain feeders with the zero sequence source behind the relaying point.

##### 90°–45° characteristic (45° MTA)

The A phase relay is supplied with current  $I_a$  and voltage  $V_{bc}$  displaced by 45° in an anti-clockwise direction. In this case, the flux due to the voltage coil lags the applied

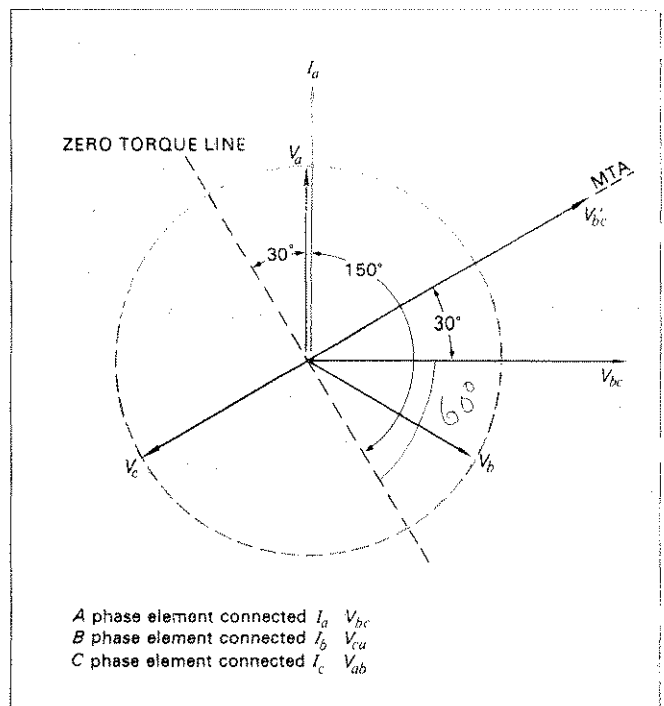


Figure 9.24 Vector diagram for the 90°–30° connection (phase A element).

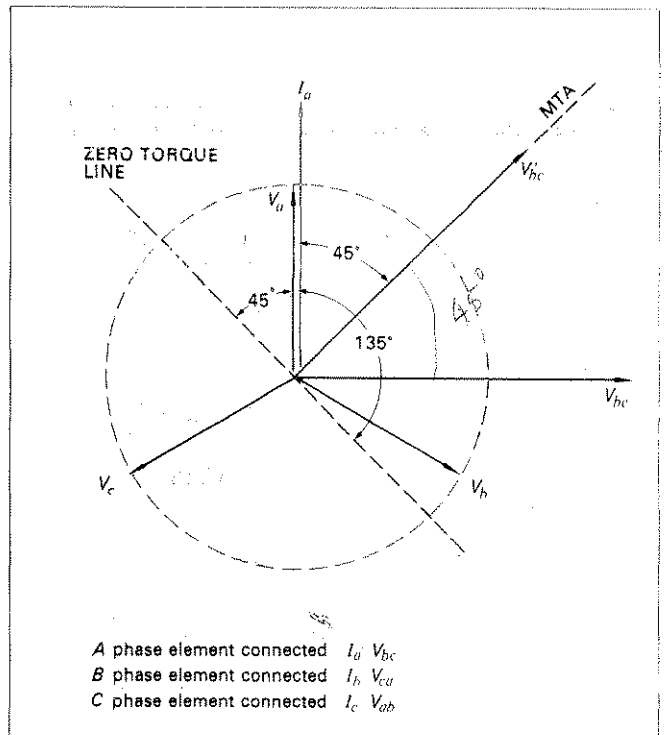


Figure 9.25 Vector diagram for the 90°–45° connection (phase A element)

voltage  $V_{bc}$  by 45°, and the relay maximum torque is produced when the current lags the system phase to neutral voltage by 45°. This connection gives a correct directional tripping zone over the current range of 45° leading to 135° lagging. The relay torque at unity power factor is 0.707 of the maximum torque and the same at zero power factor lagging; see Figure 9.25.

This connection is recommended for the protection of transformer feeders or feeders which have a zero sequence source in front of the relay. The 90°–45° connection is essential in the case of parallel transformers or transformer feeders, in order to ensure correct relay operation for faults beyond the star/delta transformer. This connection should also be used whenever single-phase directional relays are

applied to a circuit where a current distribution of the form 2-1-1 may arise.

Theoretically, three fault conditions can cause maloperation of the directional element: a phase-phase-ground fault on a plain feeder, a phase-ground fault on a transformer feeder with the zero sequence source in front of the relay and a phase-phase fault on a power transformer with the relay looking into the delta winding of the transformer. It should be remembered, however, that the conditions assumed above to establish the maximum angular displacement between the current and voltage quantities at the relay, are such that, in practice, the magnitude of the current input to the relay would be insufficient to cause the overcurrent element to operate. It can be shown analytically that the possibility of maloperation with the  $90^\circ$ - $45^\circ$  tion is, for all practical purposes, non-existent.

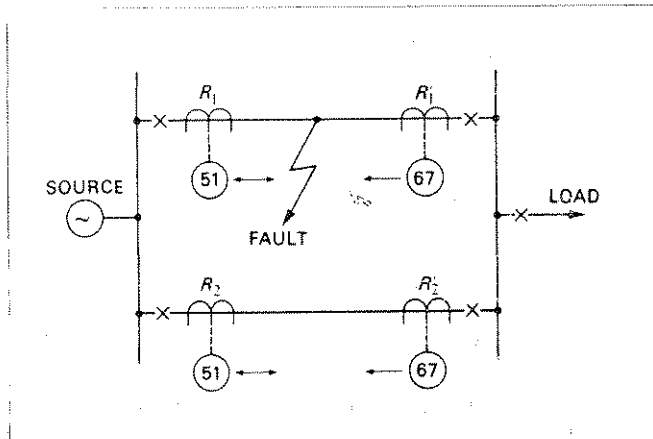


Figure 9.26 Directional relays applied to parallel feeders.

## 9.19

### PARALLEL FEEDERS

If non-directional relays are applied to parallel feeders, any faults that might occur on any one line will, regardless of the relay settings used, isolate both lines and completely disconnect the power supply. With this type of system configuration it is necessary to apply directional relays at the receiving end and to grade them with the non-directional relays at the sending end, to ensure correct discriminative operation of the relay during line faults. This is done by setting the directional relays  $R'_1$  and  $R'_2$  as shown in Figure 9.26 with their directional elements looking into the protected line, and giving them lower time and current setting than relays  $R_1$  and  $R_2$ . The usual practice is to set relays  $R'_1$  and  $R'_2$  to 50% of the normal full load of the protected circuit and 0.1 TMS, but care must be taken to ensure that their continuous thermal rating of twice rated current is not exceeded.

## 9.20

### RING MAINS

Directional relays are more commonly applied to ring mains. In the case of a ring main fed at one point only, the relays at the supply end and at the mid-point substation, where the setting of both relays are identical, can be made non-directional, provided that in the latter case the relays are located on the same feeder, that is, one at each end of the feeder.

It is interesting to note that when the number of feeders round the ring is an even number, the two relays with the same operating time are at the same substation and will have to be directional, whereas when the number of feeders is an odd number, the two relays with the same operating time are at different substations and therefore do not need to be directional. It may also be noted that, at intermediate substations, whenever the operating times of

the relays at each substation are different, the difference between their operating times is never less than the grading margin, so the relay with the longer operating time can be non-directional.

## 9.20.1

### Grading of ring mains

The usual procedure for grading relays in an interconnected system is to open the ring at the supply point and to grade the relays first clockwise and then anti-clockwise; that is, the relays looking in a clockwise direction around the ring are arranged to operate in the sequence 1-2-3-4-5-6 and the relays looking in the anti-clockwise direction are arranged to operate in the sequence 1'-2'-3'-4'-5'-6', as shown in Figure 9.27.

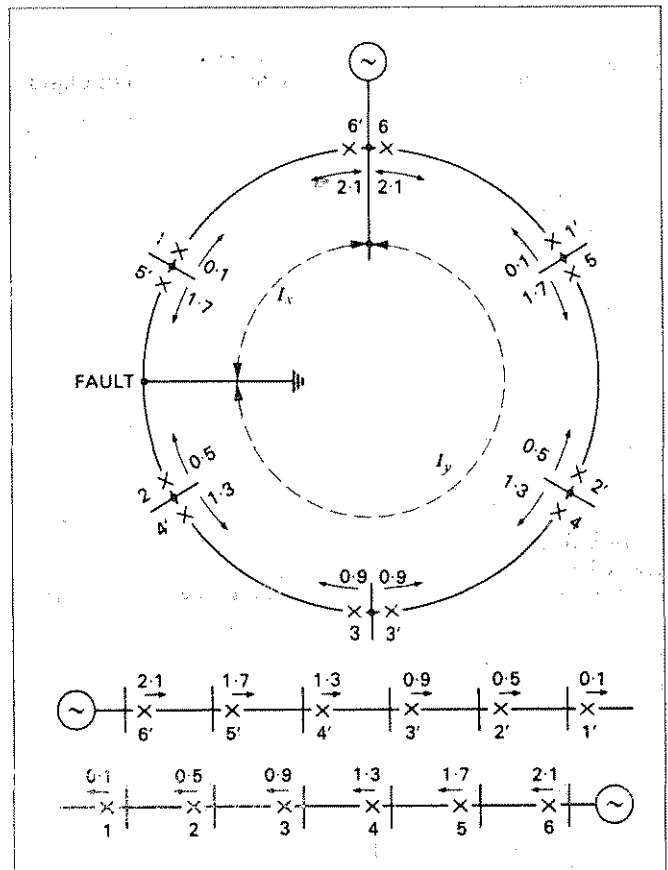


Figure 9.27 Grading of ring mains.

The arrows associated with the relaying points indicate the direction of current flow that will cause the relay to operate. A double-headed arrow is used to indicate a non-directional relay, such as those at the supply point where the power can flow only in one direction, and a single-headed arrow a directional relay, such as those at intermediate substations around the ring where the power can flow in either direction. The directional relays are set in accordance with the invariable rule, applicable to all forms of directional protection, that the current in the system must flow from the substation busbars into the protected line in order that the relays may operate.

Disconnection of the faulty line is carried out according to time and fault current direction. As in any parallel system, the fault current has two parallel paths and divides itself in the inverse ratio of their impedances. Thus, at each substation in the ring, one set of relays will be made inoperative because of the direction of current flow, and the other set operative. It will also be found that the operating times of the relays that are inoperative are faster than those of the operative relays, with the exception of the mid-point substation, where the operating times of relays 3 and 3' happen to be the same.

The relays which are operative are graded downwards towards the fault and the last to be affected by the fault operates first. This applies to both paths to the fault. Consequently, the faulty line is the only one to be disconnected from the ring and the power supply is maintained to all the substations.

When two or more power sources feed into a ring main, time graded overcurrent protection is difficult to apply and full discrimination may not be possible. With two sources of supply, two solutions are possible. The first is to open the ring at one of the supply points, whichever is more convenient, by means of a suitable high set instantaneous overcurrent relay and then to proceed to grade the ring as in the case of a single infeed, the second to treat the section of the ring between the two supply points as a continuous bus separate from the ring and to protect it with a unit system of protection, such as pilot wire relays, and then proceed to grade the ring as in the case of a single infeed.

## 9.21 DIRECTIONAL EARTH FAULT OVERCURRENT RELAYS

The relays previously described as phase fault elements respond to the flow of earth fault current, and it is important that their directional response be correct for this condition. If a special earth fault element is provided, as described in Section 9.16, a related directional element is needed.

The residual current is extracted as shown in Figure 9.18. Since this current may be derived from any phase, in order to obtain directional response it is necessary to obtain a related voltage. Such a voltage is the residual voltage of the system, which is the vector sum of the individual phase voltages. If the secondary windings of a three-phase, five limb voltage transformer or three single-phase units are connected in broken delta, the voltage developed across its terminals will be the vector sum of the phase to ground voltages and hence the residual voltage of the system as illustrated in Figure 9.28.

This will be zero for balanced phase voltages, but for simple earth fault conditions will be equal to the depression of the faulted phase voltage. In all cases the residual voltage is equal to three times the zero sequence voltage drop on the source impedance and is therefore displaced from the residual current by the characteristic angle of the source impedance. The residual quantities are applied to the directional element of the earth fault relay. When the system neutral is earthed through a resistance, this will be the dominant impedance, and a relay having a maximum torque angle of  $0^\circ$  will be satisfactory.

In the case of solidly earthed systems, the source impedance will be predominantly reactive and some degree of angle compensation is desirable. Not only may the angle between the primary residual quantities be high, perhaps  $87^\circ$ , but there is also likely to be an appreciable positive error in the VT residual voltage output, since the broken delta connection involves three times the voltage drop in the VT windings as compared with the drop when these are star-connected. This error may well make the effective angle between the secondary residual quantities exceed  $90^\circ$ , which will result in incorrect directional response.

The relay is usually provided with phase angle compensation, so that maximum torque is developed with the input current lagging the voltage by this amount.

This angle can then be subtracted from the actual phase angle between input quantities to obtain the deviation from the maximum torque condition. Exact compensation is not necessary as long as the input current vector falls well within the operative zone of the relay; a final deviation of, say,  $30^\circ$  from the maximum torque position results in a loss of torque of only 14% which is of no consequence for

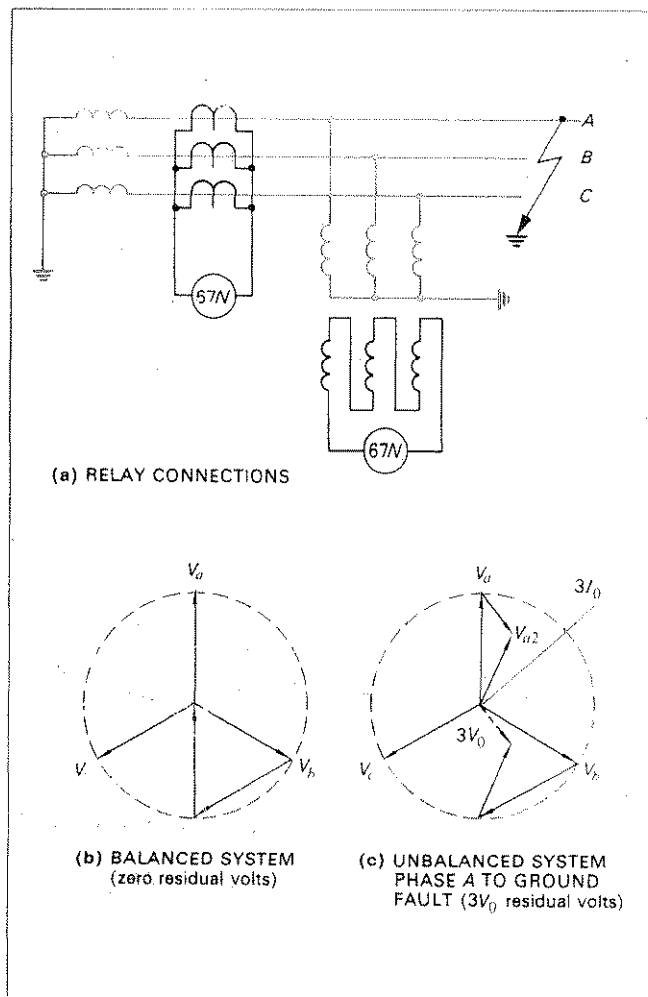


Figure 9.28 Voltage polarized directional earth fault relay.

a sensitive element. Maximum torque angles of  $45^\circ$  and  $60^\circ$  are therefore standard.

When the main voltage transformer associated with the high voltage system is not provided with a broken delta secondary winding, to polarize the directional earth fault relay, it is permissible to use three single-phase interposing voltage transformers with their primary windings connected in star and their secondary windings connected in broken delta. For satisfactory operation, however, it is necessary to ensure that the main voltage transformers are of a suitable construction to reproduce the residual voltage and that the star point of the primary winding is solidly earthed. In addition, the star point of the primary windings of the interposing voltage transformers must be connected to the star point of the secondary windings of the main voltage transformers.

### 9.21.1 Current polarization

If the residual voltage at any point in the system is insufficient to polarize a directional relay, or if the voltage transformers which are available do not satisfy the conditions for providing residual voltage, polarization can be obtained from the neutral current of a local power transformer with an earthed neutral, or the neutral current of an earthing transformer. The neutral current and line residual current are in phase, so that the relay must be designed to give maximum torque for this condition. The neutral current will always flow from the earth into the system, whereas, according to the position of the fault, the residual current may flow in either direction through the relay, so that the latter can discriminate accordingly.

When more than one transformer is operated in parallel with earthed neutrals a current transformer must be

... *Chlorophyll* ...



connections

Provided only one star point is earthed, a single current

current producing incorrect polarizing current.

less than 2:1.

Content may be up, down or in some cases even zero.

neutral, otherwise, it cannot be used.

### Dual polarization

cases a dual polarized relay is used, the windings of which

Current polar

are energized by the residual voltage and current respectively. It is likely that one or other of these quantities will be present in sufficient magnitude, but the two quantities can be applied simultaneously, supplementing each other to ensure that adequate torque is available for correct operation. It is, however, stressed that the possibility of a voltage polarized relay failing to operate is extremely remote for all system conditions likely to occur in practice.

## 9.22 POLYPHASE DIRECTIONAL RELAYS

An eight pole cup unit polyphase directional relay (type PCD) can be used in conjunction with a triple pole type CDG overcurrent relay, providing a cheaper and more compact arrangement. The relay is connected to produce the equivalent of three coupled elements connected 60° No. 1 and is unlikely to maloperate even in the limiting conditions which might lead to maloperation with three separate elements. In such cases, the element which tends to operate incorrectly is in a relatively marginal condition, producing a low torque, which, in the case of a polyphase unit, is easily overcome by the other elements, which are operating correctly under more favourable conditions.

The polyphase relay is affected by load current on sound phases; the setting for earth faults in particular may be increased very substantially, so that a polyphase relay is not recommended for use on resistance earthed systems. It may be used, however, on a solidly earthed system, provided that the minimum earth fault current at the relay location is greater than three times the full load rating of the protected circuit.

## 9.23 DUAL FED SUBSTATIONS

A dual fed substation having two incoming supply feeders and identical transformers feeding a busbar, equipped with a bus section breaker, is a popular method of obtaining power system reliability. This configuration is sometimes referred to as a 'Double Ended Substation'.

The likelihood of operating with the bus section breaker in either the open or the closed position must be taken into account in determining the settings of associated overcurrent relays.

### 9.23.1 Normally open bus section breaker

A typical dual fed substation operating with a normally open bus section breaker is controlled such that in the event of a fault or loss of primary voltage on one transformer, the respective incoming breaker is opened and the bus section breaker closed automatically.

On medium and high voltage systems the bus section breaker is not usually equipped with overcurrent protective relays, but on low voltage systems the bus section breaker is often made a duplicate of the main breakers, with identical overcurrent relays, for reasons of interchangeability and spares. When this convention is used it is also standard practice to use the same settings on the bus section breaker relays as have been selected for those associated with the main incoming breakers.

### 9.23.2 Normally closed bus section breaker

When a dual fed substation is run with the bus section breaker normally closed, only the bus section breaker and the main breaker on the faulted side should be opened to disconnect the faulty section in the event of an uncleared feeder or busbar fault.

Discrimination is obtained by setting the overcurrent relay on the bus section breaker such that its operation time

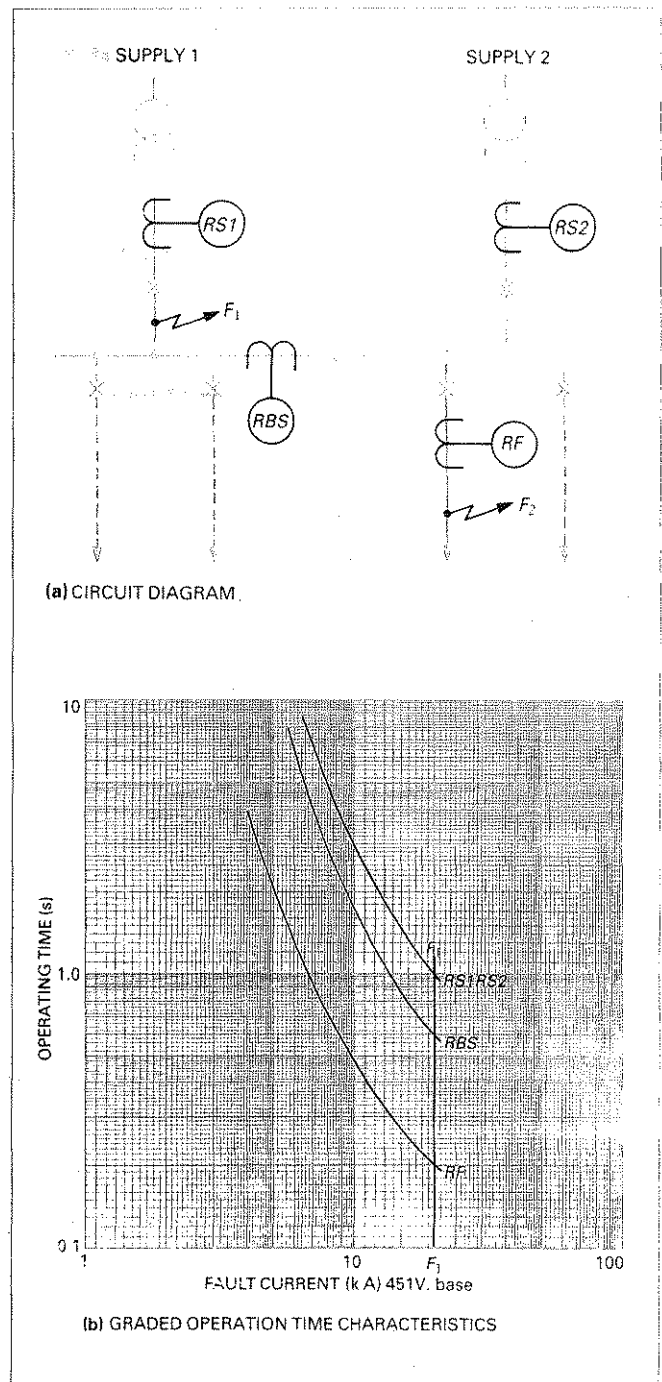


Figure 9.31 Dual fed substation: co-ordination with bus section breaker normally closed.

current characteristic lies between those of the relay on the most heavily loaded feeder(s) and the relays on the main incoming breakers, as shown in Figure 9.31. The current setting selected for the bus section overcurrent relay should be the same as that of the main incoming breaker overcurrent relays.

An important point to note is that when overcurrent devices are used in series, they may not always see the same fault current, and the double fed system with a normally closed bus section breaker is an example of this. For a fault at location  $F_2$  the feeder protection relay  $RF$  shown in diagram Figure 9.31(a) will see fault current from two sources, plus any fault current contribution from any motors on the main busbar.

Considering now a fault at location  $F_1$  the main breaker protection  $RS1$  and  $RS2$  each see fault current from only one source. If the co-ordination time between relays  $RF$  and  $RBS$  is established at fault level  $F_2$ , fast clearance is possible but with a risk that when operating with one main



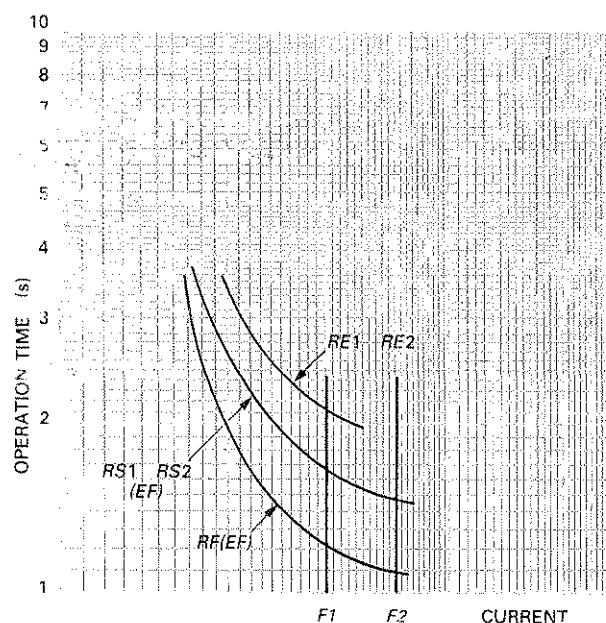
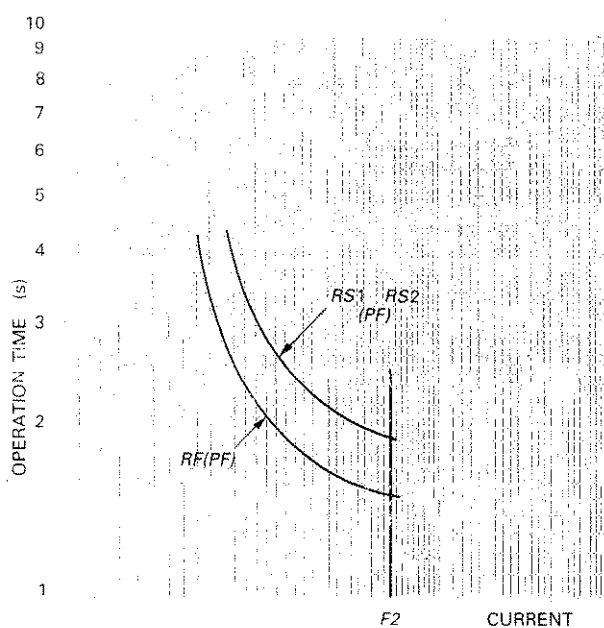
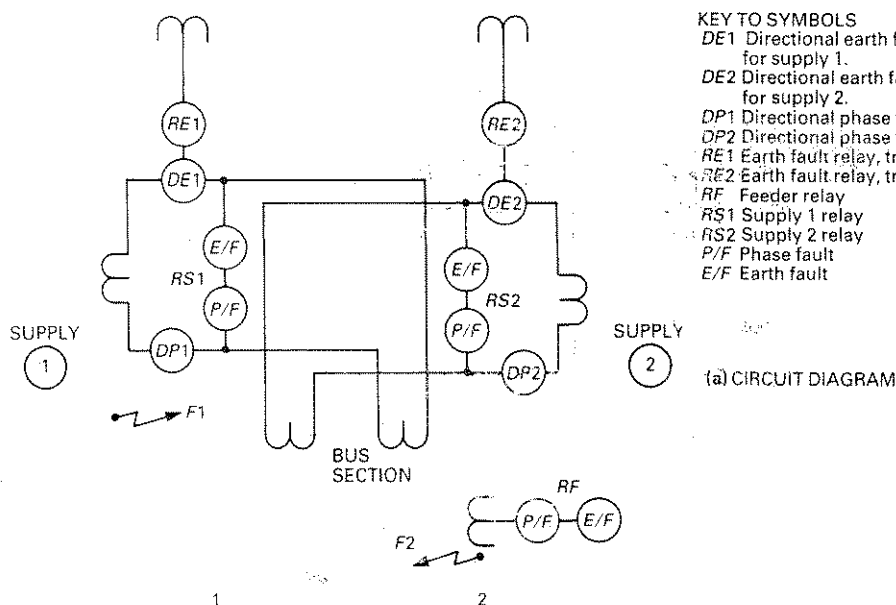


Figure 9.32 Dual fed system: 'partial differential relaying'.

breaker open and the bus section closed, loss of half the main busbar may occur.

A more secure approach is to set the co-ordination at the fault level to be expected at fault location  $F1$  as shown, thereby allowing enough time for the feeder breaker to clear the fault before the bus section breaker under both conditions.

### 9.23.3 Partial differential relaying

Of the various configurations of dual fed systems

discussed by Horcher\*, a popular scheme often applied on medium voltage substations with a normally closed bus section breaker is known as 'Partial Differential Relaying', and is shown in Figure 9.32(a).

The main advantage of this method is that in the event of an uncleared feeder fault or busbar fault, disconnection of the faulted sections is achieved without the additional time delay that would be imposed if a relay had been applied to the bus section breaker.

When the load is all supplied from only one side of the main busbar one of the relays  $RS1$  or  $RS2$  will 'see' the sum of the currents from the two sources.

\* Overcurrent Relay Co-ordination for Double Ended Substations, George R. Horcher. IEEE Vol 1A-14 No. 6 1978.



For example, if the load is all on, say, Feeder 2 shown in the diagram Figure 9.32(a), the current from supply 1 will circulate secondary current in the differential circuit of relay *RS1*, with no resultant current flowing through the relay itself. But the CT's of the other differential circuit will each transform one of the two supply currents and pass the sum of this to relay *RS2*.

The pick-up setting chosen for the phase fault elements of relays *RS1* and *RS2* should therefore be the sum of the full load currents of the two supply transformers.

The overcurrent relay discrimination curves for phase faults are shown in Figure 19.32(b), the feeder overcurrent relay discriminating with the main breaker relays *RS1* and *RS2* at the fault level corresponding to a fault at location *F2*.

As shown by the earth fault discrimination curves Figure 19.32(c), the feeder earth fault relay discriminates with the main breaker earth fault relays at fault level *F2*. Similarly the main breaker earth fault relays discriminate in turn with the earth fault relays on the transformer neutral to earth connections at the lower fault level corresponding to *F1*.

Since the system is normally operated with the bus section switch closed and the transformers in parallel, a fault on the

LV or the HV sides of a power transformer will be fed by the other transformer and continuity of supply will be threatened.

Directional relays, *DP* and *DE*, are included to prevent this by making the directional characteristic inhibit relay operation for currents flowing to the busbars from either transformer. Low current settings and short time settings are adopted to ensure fast operation and easy co-ordination with the HV side overcurrent protection.

However, it is important that the continuous thermal ratings of all the directional relays are checked to ensure that they are not exceeded.

## 9.24

### TYPICAL EXAMPLES OF TIME AND CURRENT GRADING

#### 9.24.1

##### Co-ordination with medium voltage fuses

Consider the typical arrangement shown in Figure 9.33 of a 3.3/0.415 kV system supplied from a power station auxiliary board. It is required to co-ordinate the bus section relays with the fuses on the 415 volts circuits. Discrimination is required up to 22 MVA on each of the 415 volts boards, the maximum fuse rating on the left hand board being 350A and that on the right hand board being 1000A.

In dealing with the settings required for the bus section relays, it is necessary to adopt a current setting which will firstly permit the maximum load transfer required across the section. Assuming that this value is 800 kVA, that is, 1110A at 415 volts, a satisfactory relay setting is 100% or 1500A, which corresponds to 1080 kVA. The other requirement for the relay current setting is that it shall permit suitable grading with the largest outgoing fuse.

As far as the grading margin between the relay and the fuse is concerned, the expression given in Section 9.17 will be used. This is based on the criteria outlined in Section 9.4, except that, in this case, there is no circuit breaker time to be allowed. Hence, the fixed time value used is 0.15s. The variable time value has been based on a 30% error for the fuse and 10% error for the relay. So the grading margin to be allowed between the relay and the fuse will be:

$$t' = 0.4t + 0.15 \text{ seconds}$$

where  $t$  = nominal operating time of fuse.

Now, because of the steepness of the fuse characteristic, it is considered that the best relay characteristic available is that of the extremely inverse time overcurrent relay, type CDG 14. Therefore this relay will be applied to the bus section breakers, with a setting range of 50%–200% of rated current.

##### i. Grading between the 350A fuse and the extremely inverse time relay CDG14

CDG14 relay current setting (reference G)

CT ratio 1500/5A

For this combination, a relay current setting of 100% equivalent to 1500A is satisfactory, since it permits the maximum load current requirement and is also a multiple of the fuse rating adequate to permit suitable selection of the time multiplier setting, thus ensuring correct discrimination with the fuse.

Discrimination with the fuse is required for fault levels up to 22 MVA, that is, the maximum fault level on the 415 volts busbars, which corresponds to 31,000A on a 415 V base or 20.6 times the relay current setting. From the fuse characteristic given overleaf it can be seen that the fuse operates in less than 0.01s at 31,000A. It is not worthwhile to attempt to assess actual operating times when these are

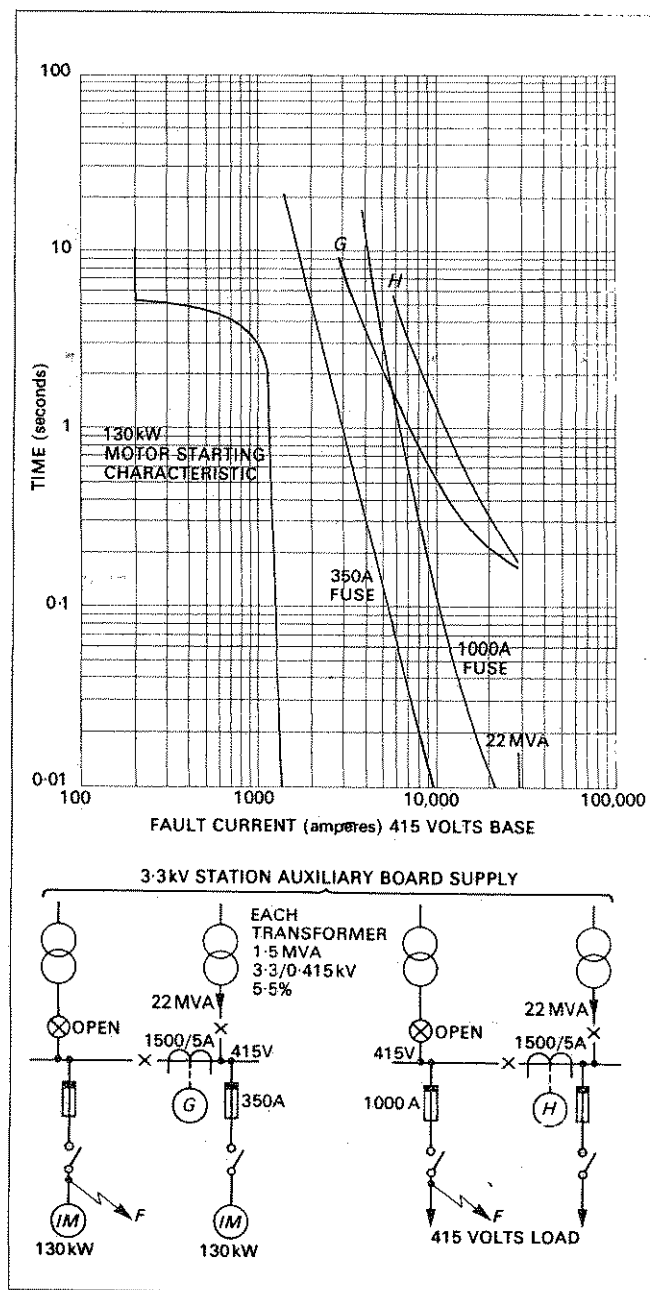


Figure 9.33 Co-ordination of inverse time relays with fuses on a 415V distribution system.

below 0.01s, a nominal operating time of 0.01s being assumed.

#### 350 A fuse characteristic

| Operating current (A) | Operating time (s) |
|-----------------------|--------------------|
| 1500                  | 20                 |
| 3000                  | 1.1                |
| 5000                  | 0.17               |
| 8000                  | 0.025              |
| 10,000                | 0.01               |

Hence, the operating time of the extremely inverse time relay CDG 14 shall be  $[0.01 + (0.4 \times 0.01) + 0.15]$  seconds, approximately 0.17 s.

#### CDG14 relay time multiplier setting

Maximum fault current for grading = 31,000 A

Relay current setting = 1500 A

$$\text{Relay PSM} = \frac{31,000}{1500} = 20.6$$

Relay operating time at 20.6 times the plug setting and 1.0 TMS = 0.32 s

$$\text{Required TMS} = \frac{0.17}{0.32} = 0.5 \text{ approximately}$$

| PSM | Current (A) | Time (s)                  |
|-----|-------------|---------------------------|
| 2   | 3000        | $18 \times 0.5 = 9$       |
| 3   | 4500        | $6.0 \times 0.5 = 3$      |
| 5   | 7500        | $2.1 \times 0.5 = 1.05$   |
| 10  | 15,000      | $0.6 \times 0.5 = 0.3$    |
| 20  | 30,000      | $0.33 \times 0.5 = 0.165$ |

The above relay characteristics (reference G) is shown in Figure 9.33 plotted on a log-log scale to a common voltage base of 415 volts, to illustrate the discrimination margin available between the relay and the fuse at the various prospective fault levels.

#### ii. Grading between the 1000 A fuse and the extremely inverse time relay CDG14

CDG14 relay current setting (reference H)

CT ratio 1500/5A

The choice of current setting for relay H is not so simple as for relay G since discrimination has to be achieved with a 1000 A fuse. As a general guide, a relay setting of approximately three times the fuse rating is satisfactory. A current setting of 200%, equivalent to 3000 A, should therefore be chosen.

Discrimination with the fuse is required for fault levels up to 22 MVA, that is, the maximum fault level on the 415 volts busbars, which corresponds to 31,000 A on a 415 V base or 10.3 times the relay current setting. From the fuse characteristic given below, a nominal operating time of 0.01 s can be assumed for the fuse.

#### 1000 A fuse characteristic

| Operating current (A) | Operating time (s) |
|-----------------------|--------------------|
| 3000                  | 100                |
| 4000                  | 17                 |
| 5000                  | 4.7                |
| 7000                  | 0.9                |
| 10,000                | 0.15               |
| 22,000                | 0.01               |

So the operating time of the extremely inverse time relay CDG 14 shall be  $[0.01 + (0.4 \times 0.01) + 0.15]$  seconds, approximately 0.17 s.

#### CDG14 relay time multiplier setting

Maximum fault current for grading = 31,000 A

Relay current setting = 3000 A

$$\text{Relay PSM} = \frac{31,000}{3000} = 10.3$$

Relay operating time at 10.3 times the plug setting and 1.0 TMS = 0.58 s

$$\text{Required TMS} = \frac{0.17}{0.58} = 0.3 \text{ approximately}$$

| PSM | Current (A) | Time (s)                  |
|-----|-------------|---------------------------|
| 2   | 6000        | $18 \times 0.3 = 5.4$     |
| 3   | 9000        | $6 \times 0.3 = 1.8$      |
| 5   | 15,000      | $2.1 \times 0.3 = 0.63$   |
| 10  | 30,000      | $0.6 \times 0.3 = 0.18$   |
| 20  | 60,000      | $0.33 \times 0.3 = 0.099$ |

The above relay characteristic (reference H) is shown in Figure 9.33 plotted on a log-log scale to a common voltage base of 415 volts, to illustrate the discrimination margin available between the relay and the fuse at the various prospective fault levels.

#### 9.24.2

#### Co-ordination of overcurrent relays for a typical industrial system

The diagram in Figure 9.34 shows part of a typical 6.6/0.415 kV industrial system, with local generation, where discriminative protection by means of inverse time overcurrent relays is required. The type and characteristic of the relays best suited to each item of plant are:

a. 6.6 kV generators (Relay reference K)

Voltage controlled inverse time overcurrent relay, type CDV 62 with a dual characteristic.

b. 6.6 kV feeders (Relay reference J)

Standard I.D.M.T. overcurrent relay, type CDG 31.

c. 6.6/0.415 kV distribution transformer (Relay reference H)

Very inverse time overcurrent relay, with high set instantaneous overcurrent elements, type CDG 63.

d. Induction motor (Relay reference G)

Thermal relay, which combines motor thermal protection with high set instantaneous overcurrent elements for short-circuit protection.

Before any relay characteristic can be plotted on log-log paper, it is necessary to choose a suitable scale for both the time and current co-ordinates and to choose a common voltage base for the current values. For convenience, it is usual to choose the voltage rating of the part of the system where the majority of the relays are located as the common voltage base and for the purpose of this example, a 6.6 kV voltage base will be used.

e. 300 A fuse characteristic

The operating characteristic of the fuse should be plotted on log-log paper to a suitable scale, in line with the maximum fault levels at the various substations, on a common 6.6 kV voltage base, as shown in Figure 9.34.

| Operating current (A) |             | Operating time (s) |
|-----------------------|-------------|--------------------|
| 415 V base            | 6.6 kV base |                    |
| 795                   | 50          | 40                 |
| 955                   | 60          | 13                 |
| 1160                  | 70          | 6                  |
| 1270                  | 80          | 3                  |
| 1590                  | 100         | 0.9                |
| 2700                  | 170         | 0.1                |

| Operating current (A)   |             | Operating time (s) |           |
|-------------------------|-------------|--------------------|-----------|
| 415 V base              | 6.6 kV base | Cold curve         | Hot curve |
| $1.25 \times 150 = 184$ | 11.57       | 1400               | 550       |
| $1.5 \times 150 = 225$  | 14.15       | 700                | 240       |
| $2 \times 150 = 300$    | 18.85       | 300                | 100       |
| $3 \times 150 = 450$    | 28.30       | 105                | 35        |
| $4 \times 150 = 600$    | 37.50       | 55                 | 18        |
| $5 \times 150 = 750$    | 47.20       | 33                 | 11        |
| $6 \times 150 = 900$    | 56.60       | 23                 | 7.5       |

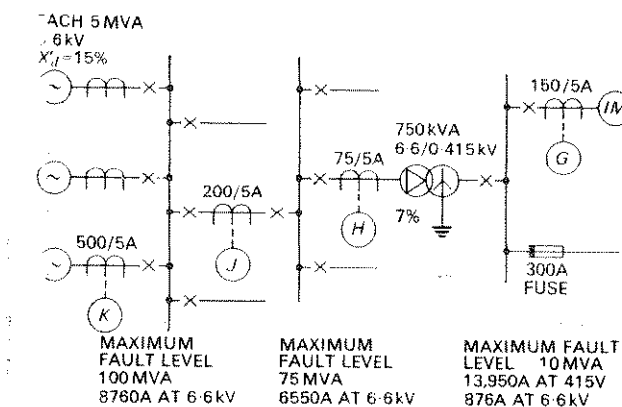
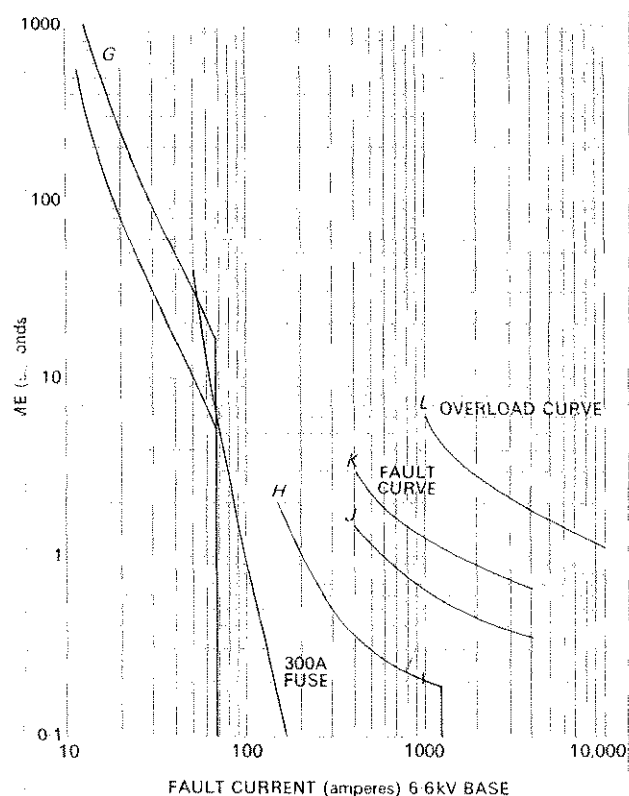


Figure 9.34 Co-ordination of inverse time overcurrent relays on a typical industrial system.

### Induction motor circuit

#### Relay G (motor relay)

It is assumed that the induction motor rating is 100 kW, which corresponds to a full load current of 140 A at 415 V, and that the motor starting current and time are 840 A and 10 seconds respectively. With a relay current setting of 100%, corresponding to 150 A at 415 V or 9.45 A at 6.6 kV, that is, 13% overload on the full load rating of the motor, the relay characteristics taken for this example are:

Now, the starting current of the induction motor is 840 A at 415 V or 52.8 A at 6.6 kV, so a current setting of  $1.3 \times 840$  A, that is, 1090 A at 415 V or 68.5 A at 6.6 kV for the high set instantaneous overcurrent element ( $I_1$ ) provided in the motor protection relay should be satisfactory, allowing healthy motor starting and giving adequate short circuit protection to the supply cable and motor. The characteristics of the motor protection relay can now be plotted on the log-log paper to the common 6.6 kV voltage base, as shown in Figure 9.34.

### 750 kVA distribution transformer

#### Relay H (CDG 63)

This relay is a composite triple pole relay, comprising a combination of very inverse time overcurrent elements type CDG 13 and high set instantaneous overcurrent elements type CAG 17. The required current and time setting for these units is determined as follows:

#### CDG13 relay current setting

CT ratio 75/5A

The full load rating of the 750 kVA transformer is 65.7 A at 6.6 kV and a relay current setting of 100%, that is, 75 A at 6.6 kV, would therefore provide an adequate margin for overload and discriminate with the 300 A fuse at the maximum fault level of 10 MVA, that is 13,950 A at 415 V or 876 A at 6.6 kV.

#### CDG13 relay time multiplier setting

Maximum fault level for grading = 876 A at 6.6 kV

Relay current setting = 75 A at 6.6 kV

$$\text{Relay PSM} = \frac{876}{75} = 11.5$$

Relay operating time at 11.5 times the plug setting and 1.0 TMS = 1.42 s.

Now, to grade the relay with the 300 A fuse at the maximum fault level of 10 MVA, the required relay operating time, as previously explained in Sections 9.17 and 9.24.1, should be  $[0.01 + (0.4 \times 0.01) + 0.15]$  seconds, approximately 0.17 s.

$$\text{Therefore required TMS} = \frac{0.17}{1.42} = 0.12 \text{ (say 0.15)}$$

| PSM | Current (A)<br>6.6 kV base | Time (s) |
|-----|----------------------------|----------|
| 2   | 150                        | 2.1      |
| 3   | 225                        | 0.86     |
| 5   | 375                        | 0.38     |
| 10  | 750                        | 0.23     |
| 20  | 1500                       | 0.18     |

#### CAG17 high set instantaneous elements setting

The instantaneous overcurrent elements must be set above

the maximum throughput capability of the 750 kVA transformer, which is:

$$65.7 \times \frac{100}{7} = 940 \text{ A at } 6.6 \text{ kV}$$

This calculation gives a pessimistically high estimate of fault current, as it makes no allowance for source impedance. This is an approximation that is frequently necessary, but in this example the source impedance has been stated in Figure 9.34, together with a more realistic figure for the maximum fault current, 876 A, to be expected on the 6.6 kV busbar.

The latter figure shows that the simpler estimate provides, in this instance, a margin of about 7%.

So the relay must be set to  $1.3 \times 940 \text{ A}$ , that is, 1220 primary amperes at 6.6 kV which corresponds to a relay current setting of 81.3 amperes or 1626%.

The operating characteristics of the composite relay CDG 63 can now be plotted on the log-log paper, to the common 6.6 kV voltage base, as shown in Figure 9.34.

### 6.6 kV feeder

#### Relay J (CDG 31)

This relay is a triple pole overcurrent relay, comprising three standard I.D.M.T. overcurrent elements, type CDG 11. The required current and time setting for these units to grade with relay H at the primary current setting of the high set instantaneous overcurrent elements, that is, 1220 A at 6.6 kV (see Section 9.6), is determined as follows:

#### CDG 11 relay current setting

CT ratio 200/5A

The current setting normally chosen for this relay would be based upon the maximum load requirements of the 6.6 kV board, plus a suitable margin for overload on the 750 kVA transformer and associated services. However, since no load values have been specified, it is assumed that a 100% current setting will be required.

#### CDG 11 relay time multiplier setting

Maximum fault level for grading = 1220 A at 6.6 kV

Relay current setting = 200 A at 6.6 kV

$$\text{Relay PSM} = \frac{1220}{200} = 6.1$$

Relay operating time at 6.1 times the plug setting and 1.0 TMS = 3.8 s.

Now, to grade relay J with relay H at 1220 A, that is, the setting of the instantaneous elements, a fixed grading margin of 0.4 s must be added to the operating time of relay H at 1220 A. Hence, the required relay J operating time should be  $(0.19 + 0.4)$ , that is, 0.59 s.

$$\text{So the required TMS} = \frac{0.59}{3.8} = 0.155$$

| PSM | Current (A)<br>6.6 kV base | Time (s) |
|-----|----------------------------|----------|
| 2   | 400                        | 1.55     |
| 3   | 600                        | 0.98     |
| 5   | 1000                       | 0.69     |
| 10  | 2000                       | 0.46     |
| 20  | 4000                       | 0.34     |

The operating characteristic of the CDG 31 relay can now be plotted on the log-log paper, to the common 6.6 kV voltage base, as shown in Figure 9.34.

### 5 MVA generators

#### Relay K (CDV 62)

This relay is a triple pole voltage controlled overcurrent relay with a dual characteristic, which changes its pick-up value when the system voltage falls, owing to a fault condition, below the drop-off value of the undervoltage relay. When this happens, the current setting of the relay is reduced to 40% of its nominal plug setting and the operating characteristic of the relay changes from a long I.D.M.T. characteristic to a standard I.D.M.T. characteristic.

This relay characteristic is chosen to cover machines having a low sustained short circuit current at reduced values of excitation because of their high synchronous reactance.

#### CDV 62 relay current setting

CT ratio 500/5A

Under close-up fault conditions, the system voltage at the generator busbars falls below the setting of the undervoltage units, and the overcurrent relay changes its operating characteristic from the overload to the fault curve. The effective current setting of the relay becomes  $(0.4 \times 500) \text{ A}$ , that is, 200 A, which happens to be the current setting of the 6.6 kV feeder relay J with which it has to grade; this means that a 100% current setting can be used for relay K.

#### CDV 62 relay time multiplier setting

The possible short circuit current from any one of the 5 MVA generators is 2920 A at 6.6 kV, so the grading between relay J and K must be carried out at this level.

Hence, the maximum fault level for grading is 2920 A at 6.6 kV. Relay current setting on the fault curve is 200 A at 6.6 kV.

$$\text{Relay PSM} = \frac{2920}{200} = 14.6$$

Relay operating time at 14.6 times the current setting on the fault curve and 1.0 TMS = 2.5 s.

Relay J operating time at 2920 amperes = 0.38 s.

Grading margin = 0.4 s.

Hence, the required relay K operating time on the fault curve should be:

$$0.38 + 0.4 = 0.78 \text{ s}$$

$$\text{Therefore required TMS} = \frac{0.78}{2.5}$$

$$= 0.312 \text{ (say } 0.3)$$

Fault curve:

| PSM | Current (A)<br>6.6 kV base | Time (s) |
|-----|----------------------------|----------|
| 2   | 400                        | 3        |
| 3   | 600                        | 1.86     |
| 5   | 1000                       | 1.29     |
| 10  | 2000                       | 0.9      |
| 20  | 4000                       | 0.66     |

Overload curve:

| PSM | Current (A)<br>6.6 kV base | Time (s) |
|-----|----------------------------|----------|
| 2   | 1000                       | 6        |
| 3   | 1500                       | 3.6      |
| 5   | 2500                       | 2.4      |
| 10  | 5000                       | 1.62     |
| 20  | 10,000                     | 1.14     |

The operating characteristics of the CDV 62 relay can now be plotted on the log-log paper, to the common 6.6 kV voltage base, as shown in Figure 9.34.

The co-ordination study of the typical industrial system is now completed; the discrimination curves of Figure 9.34 clearly indicate that the time interval between curves is satisfactory at both the maximum and minimum fault levels seen by the relays at the various locations.



# Unit protection of feeders

- 10.1 Introduction
- 10.2 Conventional grading
- 10.3 Graded overcurrent systems
- 10.4 Circulating current system
- 10.5 Balanced voltage system
- 10.6 Summation at relay point
- 10.7 Long pilot circuits
- 10.8 Practical pilot wire system
- 10.9 Carrier systems
- 10.10 Carrier differential system
- 10.11 Practical carrier system
  - Carrier superimposed

## 10.1

The graded overcurrent systems described in Chapter 9, though attractively simple in principle, do not meet all the protection requirements of a power system. Application difficulties are encountered for two reasons: first, satisfactory grading cannot always be arranged for a complex network and secondly, the grading settings may lead to maximum tripping times too long to prevent excessive disturbance of the power system.

These problems led to the concept of 'unit protection', whereby sections of the power system are protected individually without reference to other sections.

The configuration of the power system may lend itself to unit protection; for instance, a simple earth fault relay applied at the remote end of a transformer-feeder can be regarded as unit protection provided that the transformer winding associated with the feeder is not earthed. In this case the protection is restricted to the limited zone of the feeder and transformer winding because the transformer cannot transmit zero sequence current to an out-zone fault.

In most cases, however, a unit protection system involves the measurement of fault currents at each end of the zone, and the transmission of information between the equipment at zone boundaries. It should be noted that distance relays, although nominally responding only to faults within their setting zone, do not satisfy the conditions for a unit system, because the zone is not strictly speaking clearly defined; it is defined only within the accuracy limits of the measurement.

The principle of unit systems was first established by Merz and Price; their fundamental differential systems have formed the basis of many highly developed protective arrangements for feeders and numerous other items of plant. In one arrangement, similar current transformers at each end of the protected zone are interconnected by an auxiliary 'pilot' circuit, as shown in Figure 10.1. Current transmitted through the zone causes secondary current to circulate round the pilot circuit without producing any current in the relay. A fault within the protected zone will cause secondary currents of opposite relative phase compared with the through-fault condition, and the summated value of these currents will flow in the relay.

An alternative arrangement is shown in Figure 10.2, in which the CT secondary windings are opposed for through-fault conditions so that no current flows in the series connected relays.

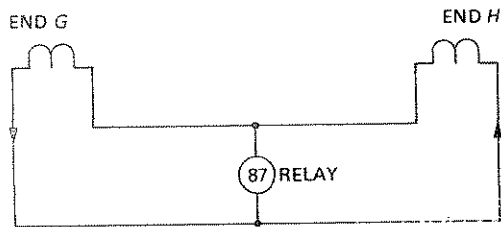


Figure 10.1 Circulating current system.

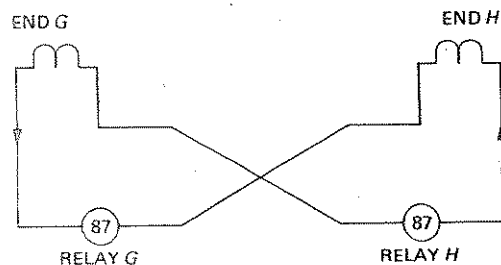


Figure 10.2 Balanced voltage system.

It is important to realize that the real object of these systems, and of others which will be discussed later, is to determine the relative direction of the fault current; this direction can only be expressed on a comparative basis, and such a comparative measurement is the common factor of many systems.

## 10.2

It is useful to establish a convention of direction; for this purpose, the direction measured from station busbars outwards along a feeder is taken as positive. Hence the notation of current flow shown in Figure 10.3, the section GH carries a through current which is counted positive at G but negative at H, while the infeeds to the faulted section HJ are both positive.

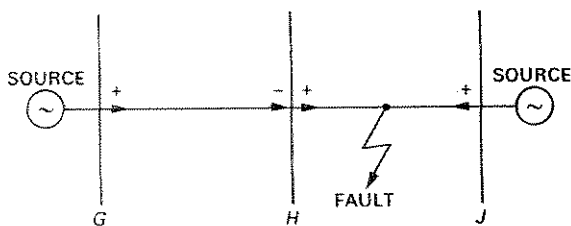


Figure 10.3 Convention of direction.

Neglect of this rule has often led to anomalous arrangements of equipment or difficulty in describing the action of a complex system. The rule when applied will normally lead to the use of identical equipments at the zone boundaries, and is equally suitable for extension to multi-ended systems. It also conforms to the standard methods of network analysis.

## 10.3

The circulating current and balanced voltage systems of Figures 10.1 and 10.2 perform full vectorial or algebraic comparison of the zone boundary currents. Such systems can be treated as analogues of the protected zone of the power system, in which CT secondary quantities represent

primary currents and the relay operating current corresponds to in-zone fault current.

These systems are simple in concept; they are nevertheless applicable to zones having any number of boundary connections and for any pattern of terminal currents.

To define a current requires that both magnitude and phase be stated. Comparison in terms of both of these quantities is performed in the Merz-Price systems, but it is not always easy to transmit all this information over some pilot channels. Comparison of the magnitude of the terminal currents is not a certain means of discrimination but the direction or phase of the currents is adequate for simple two-ended feeder applications.

Comparison of phase can be made directly or by comparing each terminal current with a third common quantity.

Direct phase comparison is achieved by transmitting the phase of each current to the remote terminal over any suitable channel, for example a telephone line, superimposed high frequency carrier signal or radio and so on.

Indirect comparison is possible, using a third quantity as a link; this quantity is usually the system voltage. The comparison process resembles the observation of apparent power, and Figure 10.3 becomes a fault power flow diagram. Power measurement is, however, a means to an end and the basic similarities of these schemes, despite the apparent differences in the techniques, should be realized.

## 10.4

### 10.4.1 THE CIRCULATING CURRENT SYSTEM

The principle of this system is shown in outline in Figure 10.1. If the current transformers are ideal, the functioning of the system is straightforward and requires little discussion. The transformers will, however, have losses which cause deviation from the ideal. The equivalent circuit of a CT can be applied to this scheme as shown in Figure 10.4(a); Figure 10.4(b) shows the distribution of potential round the pilot circuit for a current through the protected zone.

The current transformers are assumed to be identical and therefore to share equally the total circuit burden. The

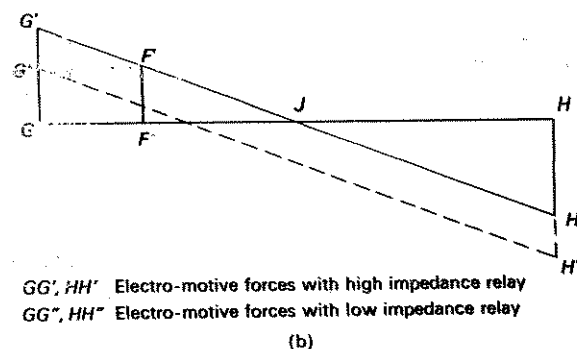
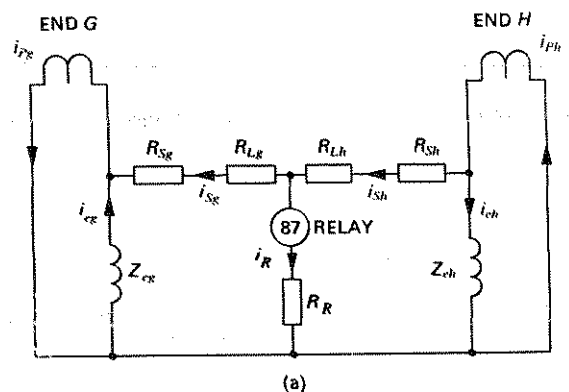


Figure 10.4 Equivalent circuit and potential diagram for circulating current system.



potential diagram indicates the situation when the relay is disconnected or of very high impedance. A point of zero potential occurs at  $J$ , the centre of  $GH$  measured in resistance values. If, however, the relay is not located at this point but at  $F$ , it will experience a voltage  $FF'$ .

When connected, a relay of low impedance will cause  $FF'$  to collapse to a low value, but the unequal burdens then imposed on the two current transformers will require unequal exciting currents  $i_{eg}$  and  $i_{eh}$ . In this case, the relay current will be given by the following equation:

$$\begin{aligned} i_R &= i_{Sg} - i_{Sh} \\ &= (i_{Pg} - i_{eg}) - (i_{Ph} - i_{eh}) \\ &= i_{eh} - i_{eg} \quad (\text{since } i_{Pg} = i_{Ph}) \end{aligned} \quad \dots \text{Equation 10.1}$$

Hence, whether the relay is of high or low impedance it will receive a 'spill' energizing quantity.

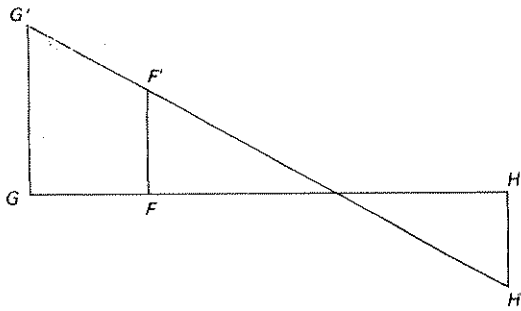


Figure 10.5 Potential diagram with unbalanced current transformers.

If the current transformers are not of equal shunt impedance, although they may be of identical turns ratio, the potential diagram is modified as shown in Figure 10.5.

With the relay branch open, the exciting currents of the current transformers must be equal because the secondary currents are of necessity identical. For this reason the electromotive forces developed by the current transformers become unequal, as indicated by ordinates  $GG'$  and  $HH'$ . This may cause either an undesirable increase in the unbalance voltage at  $F$  as shown, or a decrease.

Since it is usually inconvenient to connect the relay at the centre of the pilot loop, it was at one time common practice to add 'balancing resistors' in series with the pilots to bring the zero potential point to the position of the relay connection. Although this practice improved steady state balance, it is now subordinated to the technique needed to ensure stability under the initial transient conditions.

#### 10.4.1 Transient instability

It is shown in Section 5.3.12 that an asymmetrical current applied to a current transformer will induce a flux which is greater than the peak flux corresponding to the steady state alternating component of the current. The ratio of the transient flux to the steady state flux is proportional to the ratio of reactance to resistance in the primary system.

The very considerable build up of flux with an asymmetrical fault current may take the CT into saturation, with the result that the dynamic exciting impedance is reduced and the exciting current greatly increased.

When the balancing current transformers of a differential system differ in excitation characteristics, or are unequally burdened, the transient flux build-up will differ and an increased 'spill' current will result. This condition is not readily resolved by strict analytical methods, but a solution can be obtained for an extreme condition.

It is assumed that one CT of a balancing group becomes completely saturated while the others remain on the linear portion of the excitation characteristic and require negligible exciting current.

The shunt impedance of the saturated CT can be considered to have fallen to zero and is replaced on the equivalent diagram by a short circuit, reducing the impedance of this CT to the value of the winding resistance, as shown in Figure 10.6.

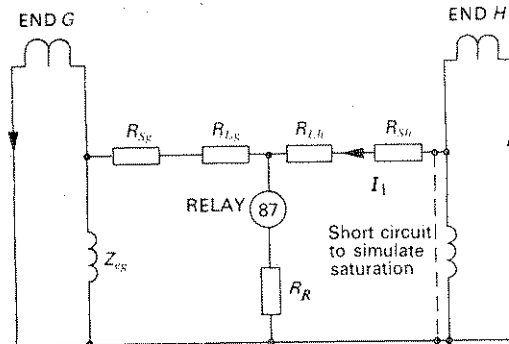


Figure 10.6 Equivalent circuit under transient conditions.

Applying the Thévenin method of solution, the voltage developed at the relay connection point is given by:

$$V = I_1(R_{Lh} + R_{Sh}) \quad \dots \text{Equation 10.2}$$

Discharging this voltage through the relay gives a current  $I_R$ , where:

$$I_R = \frac{V}{R_R + R_{Lh} + R_{Sh}} \quad \dots \text{Equation 10.3}$$

It will be seen from Equation 10.3 that if the relay resistance is low compared with the lead and winding resistances, the relay spill current may approach the value of the total secondary fault current, which is unacceptable. If, on the other hand, the relay resistance is made high, Equation 10.3 approximates to:

$$I_R = \frac{I_1(R_{Lh} + R_{Sh})}{R_R} = \frac{V}{R_R} \quad \dots \text{Equation 10.4}$$

Equation 10.4 shows that the spill current can be reduced to a value below that of any given relay setting by a suitable choice of relay resistance; this is obvious, but the equation further shows that the maximum voltage which can be applied to the relay is given by:

$$V = I_1(R_{Lh} + R_{Sh})$$

This value can be low compared with the CT knee-point e.m.f. and so a value of relay resistance ( $R_R$ ) can be chosen which will ensure stability while still permitting sensitive operation. Resistance added to the self-resistance of the relay in conformity with Equation 10.4 is known as 'stabilizing resistance'.

Referring once more to Equation 10.4, since the 'spill' voltage is the determinate quantity, it is clear that the relay current setting can be reduced to any degree, the relay being a voltage measuring device. Relay calibration can in fact be in terms of voltage.

It follows that no additional margin, above the voltage determined from resistance drop, need be allowed, since the extreme conditions of unbalanced CT saturation are not in fact realized. However it should be appreciated that the value of  $I_1$  in Equation 10.4 is the total current function. For some types of relay it may be satisfactory to use the r.m.s. value of the symmetrical wave in setting calculations, but for a very fast relay the offset peak current may be more appropriate.

In practice it is usual to base stability calculations on the r.m.s. value of the symmetrical component of fault current, a factor then being determined by test for each particular relay design. This factor ranges from two for relatively slow relays to less than unity for relays which can operate in less than one half cycle of the current.

The operating current value of this scheme is the sum of the relay operating current and the exciting current of all the parallel-connected current transformers at the setting voltage. This secondary effective setting is multiplied by the CT turns ratio to give the primary operating current.

A former practice was to fit a resistive shunt across both relay and stabilizing resistance in order to improve the stability of a given relay.

It will be clear, however, from a study of the stability equation that this so-called 'long-shunt' varies the value of  $R_R$  and the setting current, but not the setting voltage, and so has a negligible effect on the degree of stability which is achieved.

The stability equation shows that the relay setting voltage is defined by the series voltage drop. The permissible setting is limited by the e.m.f. available from each CT, so that the scheme can be applied only to a system of limited physical length, usually not more than 1000 metres. It is for this reason better suited to the protection of plant and is only used for very short feeders. The theory of the system is included in this chapter for the sake of completeness.

## 10.5

The balanced voltage system, which is the dual of the circulating current system, is shown in Figure 10.2.

With primary through current, the secondary electromotive forces of the current transformers are opposed, and produce no current in the interconnecting pilot leads or the series connected relays. An in-zone fault leads to a circulating current condition and hence to relay operation.

An immediate consequence of the arrangement is that the current transformers are in effect open-circuited, as no secondary current flows for any primary through-current conditions. To avoid excessive saturation of the core, and secondary waveform distortion, the core is provided with non-magnetic gaps sufficient to absorb the whole primary m.m.f. at the maximum current level, the flux density remaining within the linear range. The secondary winding therefore develops an e.m.f. and can be regarded as a voltage source. The shunt reactance of the transformer is

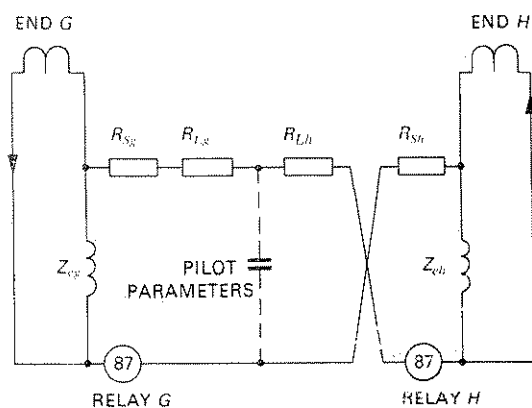


Figure 10.7 Equivalent circuit for balanced voltage system.

relatively low, so the device acts as a transformer loaded with a reactive shunt; hence the American name of transactor.\*

The equivalent circuit of the system is as shown in Figure 10.7.

The series connected relays are of relatively high impedance; because of this the CT secondary winding resistances are not of great significance and the pilot resistance can be moderately large without affecting the operation of the system overmuch. This is why the scheme was developed for feeder protection.

## 10.5.1

### Stability limit of the voltage balance system

Unlike normal current transformers, transactors are not subject to errors caused by the progressive build-up of exciting current, because the whole of the primary current is expended as exciting current.† The secondary e.m.f. is in consequence an accurate measure of the primary current within the linear range of the transformer. Provided the transformers are designed to be linear up to the maximum value of fault current, balance is limited only by the inherent limit of accuracy of the transformers, and as a result of capacitance between the pilot cores. Such capacitance is indicated by a broken line in the equivalent circuit shown in Figure 10.7. Under through-fault conditions the pilots are energized to a proportionate voltage, the charging current flowing through the relays. The stability ratio that could be achieved with this system was only moderate; various means were adopted to overcome the inherent limitations. The most successful of these techniques, and virtually the only survivor, is bias.

## 10.5.2

### Bias

The 'spill' current in the relay arising from these various sources of error is dependent on the magnitude of the through current, being negligible at low values of through-fault current but sometimes reaching a disproportionately large value for more severe faults. The simple systems, with a fixed differential setting, had to be designed so that this setting exceeded the worst spill current which was likely to occur; this gave poor sensitivity which was not always adequate. The performance is greatly improved by making the differential setting approximately proportional to the fault current. This is achieved by the provision of a restraining force derived either from the total fault current or the fault current flowing through the local terminal. The minimum operating level can then be made low with the assurance that the differential setting will be much increased when large fault currents flow, so that the spill currents which may then occur will not cause unwanted operation. This subject is treated more fully in Section 6.5.

## 10.6

### TRANSACTOR ARRANGEMENTS

Schemes have so far been discussed as though they were applied to single-phase systems. A polyphase system could be provided with independent protection for each phase, but this would involve a corresponding number of pilot channels, which for a feeder would usually be prohibitive in cost. The alternative is to combine the separate phase currents into a single quantity for comparison over the pilot channel.

Direct summation of the currents in a three-phase system would produce an output proportional only to the zero sequence component. Other arrangements must be used to obtain an output under all practical fault conditions.

\* The alternative name for this device—quadrature current transformer—refers to the quadrature relation between primary current and secondary e.m.f., which is of importance in some contexts.

† This statement is literally true in terms of a solution by Thévenin's method, as the e.m.f. is determined for the condition of open-circuited pilots.

### 10.6.1

#### Summation windings

A winding, either on a measuring relay or on an auxiliary current transformer, is arranged as in Figure 10.8.

The interphase sections of this winding,  $A-B$  and  $B-C$ , are often given an equal number of turns; the neutral end of the winding,  $C-N$ , will generally have a greater number of turns.

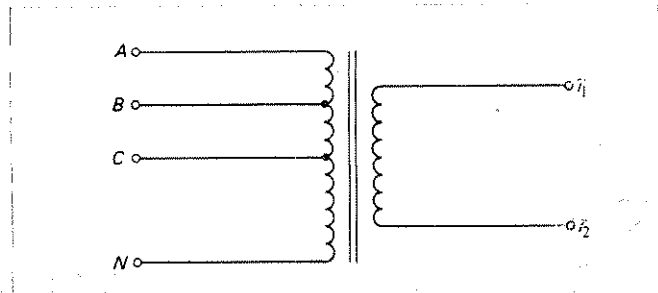


Figure 10.8 Typical summation winding.

This winding has a number of special properties, which are noted below.

#### Sensitivity

Unbalanced fault currents will energize different numbers of turns, according to which phase is faulted. This leads to relay settings which are in inverse ratio to the number of turns involved. If the relay has a setting of 100% for an  $A-B$  fault, the following proportionate phase fault settings apply:

|             | Setting |
|-------------|---------|
| Phase $A-B$ | 100%    |
| Phase $B-C$ | 100%    |
| Phase $A-C$ | 50%     |
| Three-phase | 58%     |

The earth fault settings will depend upon the relative number of turns in section  $C-N$ , but will also vary according to which phase is faulty.

#### Response to 1-2-1 pattern of currents

Phase currents in a 2-1-1 pattern result from phase-phase short circuits on the remote side of a delta-star transformer. The larger current flows in the opposite direction to that of the current in the other two phases. When the larger current flows in the  $B$  phase, the summation winding of Figure 10.8 will have equal currents of opposite sign flowing in the two phase sections, resulting in mutual cancellation and therefore zero output. Since such currents in a feeder are always through-currents to an out-zone fault, lack of sensitivity would not appear to matter. However, as there is always the possibility of a 'spill' current, caused by CT errors, being discharged through the neutral end turns, some energization may occur. Since this spill quantity cannot be expected to balance between the two devices at the ends of the zone, and the lack of substantial energization leaves the relays without an appropriate bias, instability may occur.

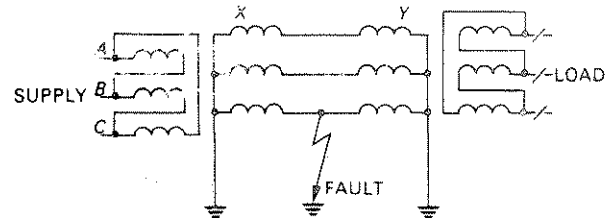
To overcome this effect, the  $A-B$  and  $B-C$  sections of the winding are sometimes made unequal, so that the 1-2-1 pattern of input currents produces an output. If this is done the range of settings will be greater.

#### Effect of zero sequence current distribution in a multiple earthed system

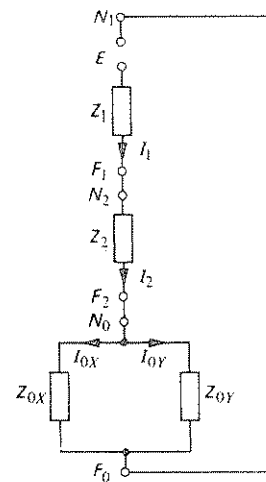
The summation winding gives a satisfactory response for simple fault conditions in which the proportion of sequence components in the fault current is maintained at the measuring point. However, when a fault occurs on a line interconnecting two stations, the sequence com-

ponents in the fault current may be supplied in disproportionate amounts from the two stations so that the blend of sequence components in the two line ends differs.

Such a condition is shown in Figure 10.9(a). The line  $XY$  interconnects two transforming stations, the line being connected to earthed star windings at each station. A source of supply exists at station  $X$ , whereas station  $Y$  is coupled only to a passive network, which for the present is taken to have negligible positive sequence admittance. The



(a)



(b)

Figure 10.9 Feeder phase to earth fault in a multiple earthed system.

effect of an earth fault on phase  $C$  is considered.

The sequence diagram can be reduced to the form shown in Figure 10.9(b). The line currents are applied to the summation windings of a differential protection system having turns in the ratio 1:1.

The resultant number of ampere-turns at  $X$  is given by:

$$AT_{XR} = I_1[(2+n)a^2 + (1+n)a + n] + I_2[(2+n)a + (1+n)a^2 + n] + I_{0X}[(n+2) + (n+1) + n] \quad \dots \text{Equation 10.5}$$

In general,  $I_1$  and  $I_2$  can be taken as equal.

Hence:

$$AT_{XR} = -3I_1 + 3I_{0X}(n+1)$$

Also:

$$I_1 = I_{0X} + I_{0Y}$$

Let

$$\frac{I_{0Y}}{I_{0X}} = R$$

Then:

$$AT_{XR} = 3I_{0X}(n-R) \quad \dots \text{Equation 10.6}$$

$$AT_{YR} = 3I_{0Y}(n+1) = 3I_{0X}R(n+1) \quad \dots \text{Equation 10.7}$$

Equation 10.6 shows that provided  $R$  is less than  $n$ ,  $AT_{XR}$  will be positive (see direction conventions in Section 10.2) and the system will operate correctly.

If  $R$  is equal to  $n$ ,  $AT_{XR}$  will be zero and the system might trip at the end  $Y$  only; whether or not tripping occurs at end  $X$  will depend on the details of the system design. If only  $Y$  end trips, the change in phase currents at end  $X$  will lead to a sequential trip.

If  $R$  is greater than  $n$ ,  $AT_{XR}$  will be negative. A differential system will then operate only if the bias ratio  $B$  is less than  $\frac{I_{YR}}{I_{XR}}$ , that is, less than  $\frac{R(n+1)}{R-n}$ . The term  $\frac{R}{R-n}$  is greater than unity, but approaches this value when  $R$  is much larger than  $n$ , so that provided  $B$  is less than  $(n+1)$  the system will always be able to operate, whatever the ratio of  $Z_{OY}$  to  $Z_{OX}$  may be.

It is possible to exceed the limiting bias ratio derived above if it is remembered that  $R$  can not be infinite. If the bias characteristic is curved as shown in Figure 10.10, the bias can be high for high fault currents; when the value of  $R$  is high the possible fault current will be low, so that, provided the bias curve lies below the ampere-turns ratio curve, satisfactory operation will occur.

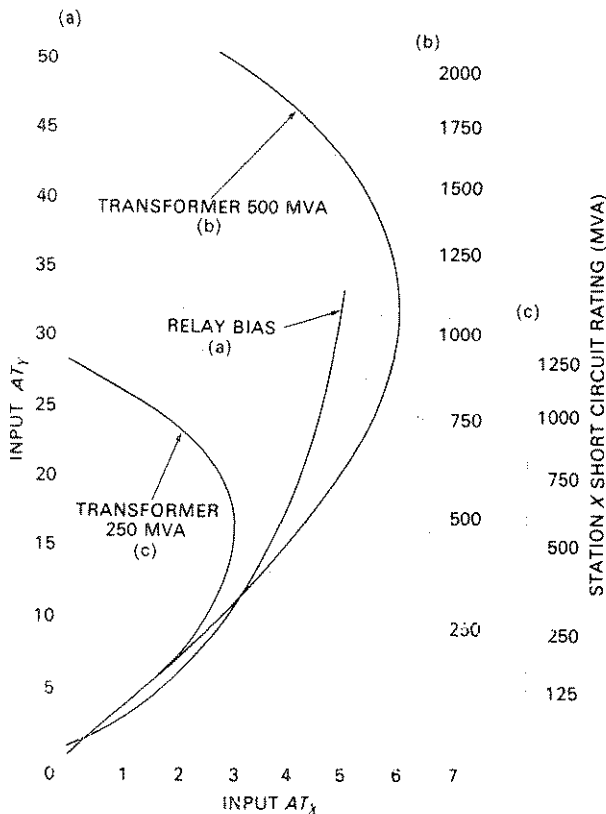


Figure 10.10 Response of differential system with summation winding for C phase to earth fault on multiple earthed system.

The energizing ampere-turns at  $X$  and  $Y$  are given by:

$$AT_X = \frac{3(n-R)}{(2R^2 + 3R)} \frac{E}{Z_{OY}}$$

$$AT_Y = \frac{3R(n+1)}{(2R^2 + 3R)} \frac{E}{Z_{OY}}$$

where  $E$  = per unit system e.m.f.

$Z_{OY}$  = per unit transformer impedance at  $Y$ .

Current transformers are assumed to match transformer rating and have a secondary rating of 1A.

Line impedance is included in  $Z_{OY}$ . Figure 10.10 shows the  $AT_Y/AT_X$  locus curves for two transformer banks and a possible protective relay bias curve. The curves show that the protection would operate satisfactorily with the smaller transformer bank but might fail to operate with the larger one.

## 10.6.2

### Sequence networks

Networks that respond to one of the symmetrical components of the current can be used as a source of the current for comparison in the differential system. The negative sequence component does not occur in a balanced load, and, when present on a faulted line, always flows towards the fault. The need for a response to three-phase faults means that sensitivity to the positive sequence component is also required. It is necessary to proportion these two quantities so as to ensure that no system condition occurring in practice gives rise to a 'blind spot' similar to those possible with summation transformers.

A detailed study\* has shown that a satisfactory performance is obtained with a relaying quantity  $I_m$  given by:

$$I_m = 6I_2 - I_1$$

...Equation 10.8

Sequence networks on this basis have been used in America for differential protection, but British practice has remained with the summation technique, the bias and winding ratios being correctly proportioned.

For phase comparison protection, since no reversal of polarity is permissible (that is  $n > R$  for correct operation with a summation transformer) it is now general practice to use a sequence network summation arrangement that produces an output as given by Equation 10.8 above.

## 10.7

The pilot circuit has been treated above as a simple interconnection, although mention has been made of the effects of resistance and capacitance. The circuit is in effect a transmission line, operating in conjunction with the relay equipment and in some cases very near the power transmission line. The performance of the pilot circuit may be complex and the operation is made even more involved by inductive interference effects.

### 10.7.1

#### Pilot circuit characteristics

A circuit comprising a pair of light gauge conductors will have resistance and shunt capacitance distributed over the pilot length. The inductance of the circuit is usually negligible, although sometimes inductance is added in the form of 'loading coils' connected in series at regular intervals. Such inductance is only necessary when the line is required to transmit communication signals as well as to perform a protection function.

When the line is of moderate length, that is, up to about fifteen miles (24 km), it may be represented by a 'tee' circuit with the capacitance treated as a single unit connected to the mid-point of the series resistance.

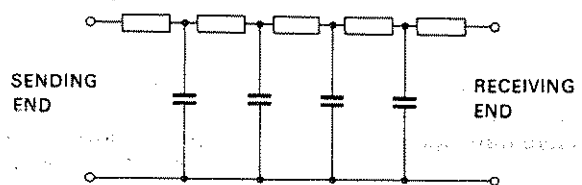


Figure 10.11 Multi-tee circuit representation of pilot circuit.

\* Selection of Relaying Quantities for Differential Feeder Protection, Adamson & Talkan, IEE Journal, 1960.

For longer circuits this representation is not sufficiently accurate, and it becomes necessary to represent the circuit by a number of such tee elements connected in series, forming a 'ladder' circuit, as in Figure 10.11.

The behaviour of a long line can be determined by calculation of the apparent impedance of such a ladder, or by applying the analytical solutions for such a line.

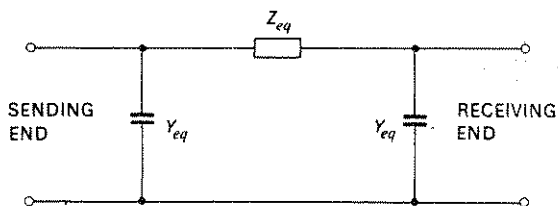


Figure 10.12 Equivalent circuit of pilot line.

The line can be represented by an equivalent circuit, Figure 10.12, in which the constants are given by:

$$Z_{eq} = Z \left( 1 + \frac{YZ}{6} + \frac{(YZ)^2}{120} + \frac{(YZ)^3}{5040} + \dots \right)$$

$$Y_{eq} = Y \left( \frac{1}{2} - \frac{YZ}{24} + \frac{(YZ)^2}{240} - \dots \right)$$

$Z$  is the total series impedance of the line.

$Y$  is the total shunt admittance of the line.

For lines of up to 15 miles of 20lb conductor, with a resistance of approximately 1300 ohms, only the first term of the expansions need be used. (This conductor is equivalent to approximately 24km of 0.9mm diameter telephone type cable.)

The significance of the 'long line' performance can be seen from Figure 10.13, which shows the curves of input impedance for the alternative cases of the line being open-circuited or short-circuited at the receiving end.

For really long lines the open-circuit and short-circuit impedances merge, so that it is not possible to determine the

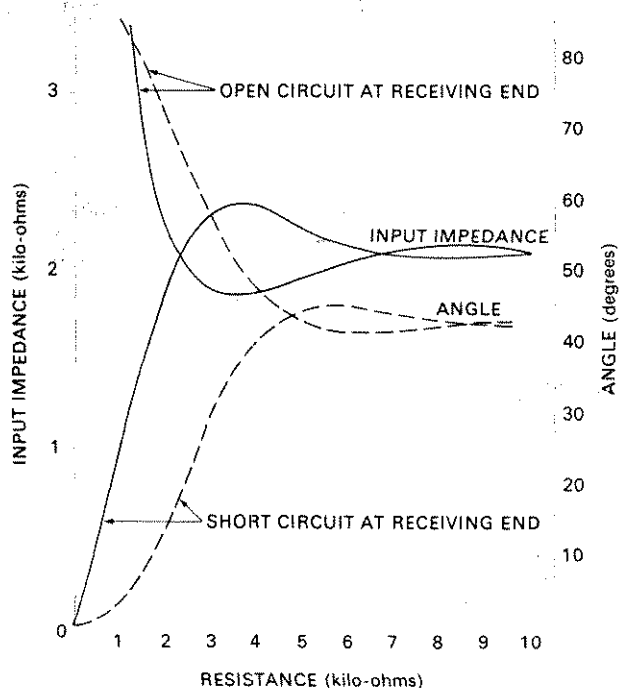


Figure 10.13 Input impedance of 20lb pilot circuit: (Equivalent to 0.9mm diameter telephone type cable).

condition of the far end of the line from an impedance measurement. This is a real problem in the application of a differential scheme, because it is the apparent impedance of the pilot circuit that conveys to the relay the information as to the direction of the current at the remote station.

Open-circuit and short-circuit conditions are arbitrary criteria, and do not represent the total range of terminal conditions. Pilot response can be improved by reactive compensation; shunt reactors are connected across the pilot circuit to compensate for the capacitance current. Ideally, these reactors should be placed at intervals along the pilot, but for practical reasons, are applied only at the ends, as part of the relay equipment. The tuning of the circuit is not sharp because of the pilot resistance, 2 being the maximum  $Q$  factor obtainable in typical cases, but this nevertheless gives a useful increase in open-circuit impedance, allowing a voltage balance scheme to be used with a longer pilot circuit than would otherwise be practicable.

## 10.7.2

### Interfering signals

The field of any adjacent conductor may induce a voltage in the pilot circuit; when this is laid parallel to a power circuit the induced voltage may be considerable, particularly when a severe earth fault occurs on the power circuit. In these circumstances, particularly when the power circuit is part of a solidly earthed EHV system, the voltage may amount to several thousand volts. The current that will flow if the pilot line is earthed at each end is limited only by the line resistance, reactance being small, and may be of the order of 100A. The effect is therefore associated with substantial power and can cause considerable damage.

It should be realized that an auxiliary line run between stations, for whatever duty, and whether associated with power equipment or not, is inherently dangerous and should be treated at all times as a high voltage circuit.

The voltage that may be induced can be calculated from the following formula:

$$e = 0.232 I_e \log_{10} \frac{D}{S}$$

where  $e$  = induced voltage per mile (V)

$I_e$  = single-phase/earth fault current (A)

$D$  = equivalent depth of earth return (typically 1500-3000 feet)

$S$  = distance of pilot from phase conductor (feet).

If the pilot cable is enclosed in a lead sheath, earthed at each end, a certain amount of screening is provided by the current in the sheath; a measurement may show a voltage of only one half of that calculated by the above formula.

A rise in ground potential caused by the flow of earth fault current through the earth contact resistance of earthing electrodes can add to the induction effect.

The induced voltage discussed above is of like polarity in both conductors of a pilot pair and should therefore produce no transverse voltage, the primary effect being stress on the insulation of the terminal equipments. If the operation of the equipment is not important during system faults, overvoltage protection can be provided by discharge devices such as spark-gaps, neon tubes, ceramic non-linear resistors and so on. System protection, however, must be fully functional at such a time.

The use of diverters of any type which tends to short-circuit the pilots when it discharges is therefore not permissible. The pilot circuit and all directly connected equipment should be insulated from earth and other circuits to an adequate voltage level; two levels of 5kV and 15kV are recognized as standard. To this end, relay contacts are operated by long push-rods of insulating material, or are

carried on such rods attached to the relay movement. The frame of the relay can be insulated from earth where appropriate. Alternatively, the pilot circuit can be coupled to the protective relays and ancillary equipment by isolating transformers, which embody the necessary insulation.

Although the longitudinal voltages, being equal and of like polarity, should produce no transverse effect, the pilot circuit is nevertheless unlikely to be completely free of static. Any imbalance in the characteristics of the pilot conductors will lead to a certain amount of transverse voltage; other hypothetical means whereby a transverse voltage might be induced have also been suggested.

Such transverse interfering voltage may reach a value of 0.1% of the longitudinal voltage.

If, instead of being two cores selected at random from a multi-core cable, the pilot conductors are separately twisted with a short pitch, the degree of unbalance that can occur is very much reduced and the induced transverse voltage becomes very small. This practice is recommended for all differential protection pilots.

### 10.7.3

#### Supervision of pilot circuits

Pilot circuits are subject to a number of hazards, such as:

##### *Manual interference*

If the pilot conductors are part of a multi-core cable which provides a number of services, for example telecommunication or control telemetering, as well as protection, it is possible that maintenance personnel may disconnect the protection pilots in error.

##### *Open wire pilots*

These are vulnerable to storm damage and miscellaneous accidents that may cause a break or a short circuit.

##### *Buried pilot cables*

Damage can be caused to these during excavation work, particularly where mechanical excavators are used. They can also be broken by ground subsidence, and cracks in the outer sheathing, particularly of paper-insulated lead-sheathed cables, may allow moisture to seep in, giving rise to low insulation resistance.

In many cases continuous supervision of the pilots is considered worthwhile. This can be done by injecting into the pilot circuit a small uni-directional current derived from an auxiliary power source. The supervision current, which is routed or otherwise arranged so as not to affect the protection relays, maintains an auxiliary relay in an operated condition at the end remote from the injection point. The relay signals a pilot fault on resetting, usually after a time delay of a few seconds, introduced to prevent the transmission of signals during primary system faults as a result of depression of the auxiliary supply voltage. The auxiliary supply is itself often supervised by another auxiliary element at the injection end.

Such a system will detect open-circuit or short-circuit faults; by polarizing the receiving relay it is also possible to detect if pilots have been reconnected with reversed polarity after a disconnection.

In an alternative arrangement, the pilots form one arm of a Wheatstone bridge. The sensing relay is then at the injection point, which may have some convenience in signalling alarms. This scheme can detect not only major pilot faults but also changes in resistance, a factor which is important if the pilots are rented from another authority; see Section 10.7.4(e).

The object of supervision is to warn that the protection is unsound because of a pilot fault, so that suitable steps can be taken before the circuit is tripped unnecessarily. In order to achieve this object it is necessary to ensure that the

three-phase setting of the scheme exceeds any expected value of load current.

Either of two methods may be used:

- a. Adjusting the basic three-phase setting to a suitable value.
- b. Providing phase and earth fault overcurrent check relays. These can be instantaneous elements, with contacts connected in series with the differential relay contacts in the tripping circuit. This is the better method in that the same setting can apply to all phases, whereas in the former method the least sensitive phase setting may be very high.

If this procedure is followed, a pilot fault will be signalled without the circuit tripping; a mis-trip will occur only in the unlikely event of faults simultaneously on the pilot and the power system.

### 10.7.4

#### Rented pilot circuits

In certain circumstances it is economical to rent circuits from the telephone authority; these circuits are obtained on a continuous basis without involving exchange equipment. A special undertaking is given that the circuit will not be interfered with without notice.

The following limitations generally apply to such circuits:

- a. The telephone authority will usually impose limits on the amount of voltage and current which may be transmitted at any time. Typical values are 130 volts peak and 60mA r.m.s. in a high resistance circuit for fault duration only.
- b. High voltage isolation is required between the pilots and all other circuits, including earth. This is to protect the pilots and not because of any voltage induced in them, as the pilots are routed away from power circuits. Insulation to withstand a 15kV test is usually provided.
- c. Spark-gaps are connected between CT secondary circuits and earth, to assist in the discharge of current should a CT breakdown occur.
- d. The pilots are of light construction, typically 20lb per mile conductor, and consequently have a relatively high resistance.
- e. The risk of manual interference remains, making continuous supervision essential. Cases have occurred in which the pilot circuit has been re-routed through a different cable without operating the simple supervision system. Since the new cable may have different characteristics from the original one, the changes may seriously affect the performance of the protection. It is therefore desirable that supervision should be of the resistance measuring type.

So much attention has been given to the special handicaps of rented telephone-type pilots that the performance of such installations is now statistically better than that of systems using privately-owned pilots. This somewhat paradoxical statement must be seen as evidence of the success which has been achieved with rented pilots rather than as denigrating the use of private pilots, which, if well installed with due regard to all the hazards, are ideal.

### 10.8

#### BIASED VOLTAGE SYSTEMS

As mentioned above, the original balanced voltage system has been replaced by biased systems. Several of these have been designed, some of which appear to be quite different from others. These dissimilarities are, however, superficial. A number of these systems are described below.

### 10.8.1

#### 'Translay'

'Translay' is the trade name initially given to a biased, electromechanical balanced voltage system introduced more than half a century ago and which is still giving useful

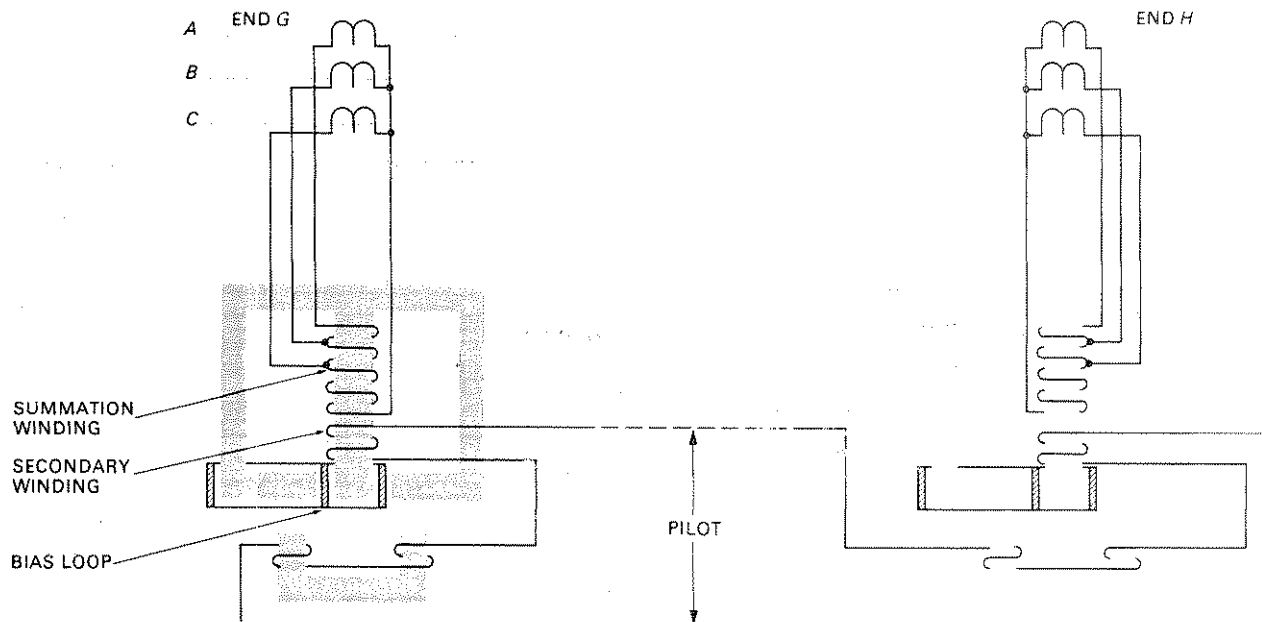


Figure 10.14 Translay electromechanical differential protection system.

service on distribution systems, though it remains fundamentally unchanged.

A modern static pilot wire system, using the circulating current principle and designated Translay 'S', is described in a later Section 10.8.4.

The electromechanical design derives its balancing voltages from the transactor incorporated in the measuring relay at each line end. The latter are based on the induction-type meter electromagnet as shown in Figure 10.14.

The upper magnet carries a summation winding to receive the output of current transformers, and also a secondary winding which delivers the reference e.m.f. The secondary windings of the conjugate relays are interconnected as a balanced voltage system over the pilot channel, the lower electromagnets of both relays being included in this circuit.

Through current in the power circuit produces a state of balance in the pilot circuit and zero current in the lower electromagnet coils. In this condition, no operating torque is produced.

An in-zone fault causing an inflow of current from each end of the line produces a circulation of current in the pilot circuit and the energization of the lower electromagnets, which co-operate with the flux of the upper electromagnets to produce an operating torque in the discs of both relays.

An infeed from one end only will result in relay operation at the feeding end, but no operation at the other, because of the absence of upper magnet flux.

Bias torque is produced by a copper shading loop fitted to the pole of the upper magnet, thereby establishing a Ferraris motor action that gives a reverse or restraining torque proportional to the square of the upper magnet flux value.

A further effect of the shading loop is to adjust the phase of the pole tip flux. Current flowing into the pilot line capacitance will lead the secondary e.m.f., and will therefore be substantially in phase with the upper magnet flux. This is a condition of low torque, but this inherent insensitivity to pilot capacitance current is limited by the pilot resistance. The phase adjustment of the pole tip flux increases the value of capacitance current that can be tolerated and enables the system to be applied with relatively long pilots.

A permanent magnet is fitted for damping, giving further improvements of both mechanical and transient stability.

### Settings

The standard relay, type HO4, which is suitable for the majority of distribution systems, has the following settings:

|                                   |               |
|-----------------------------------|---------------|
| Least sensitive earth fault       | 40% of rating |
| Least sensitive phase-phase fault | 90% of rating |
| Three-phase fault                 | 52% of rating |

For systems in which the earth fault current is severely limited, a relay with a better earth fault sensitivity is available. This relay, type HOC4, also has a coil tap which enables the standard earth fault sensitivity to be obtained.

A further feature is another tap which enables a higher phase fault setting to be selected; this may be used to ensure that the relay does not trip with normal load current in the event of a pilot fault.

This relay should not be used if the maximum earth fault current exceeds ten times the CT rating.

The following alternative settings are available:

|                                   |                                 |
|-----------------------------------|---------------------------------|
| Least sensitive earth fault       | 40%, 28%, 15% or 13% of rating. |
| Least sensitive phase-phase fault | 90% or 180% of rating.          |
| Three-phase fault                 | 52% or 104% of rating.          |

With both models, the basic settings quoted above can be raised by a factor of up to just over 2, using a continuously adjustable calibrated torsion head to control the spring tension.

### Pilot conditions

The reference voltage obtained from the Translay relay is not a linear function of the current; saturation is allowed to occur, but the electromagnets are adjusted to a standard to maintain balance.

Accepting saturation permits the relay to be compact compared with the physically much larger transactors used in the original Merz-Price scheme.

The conditions imposed on the pilots are also relatively mild. The relay torque is derived from the interaction of two fluxes, one of which is produced directly from the local CT secondary current. The second flux is derived from the pilot current, which may be relatively small. The scheme can therefore operate with fairly long pilots of up to at least 1000 ohms, with some increase in the effective setting. The r.m.s. voltage impressed on the pilots does not exceed



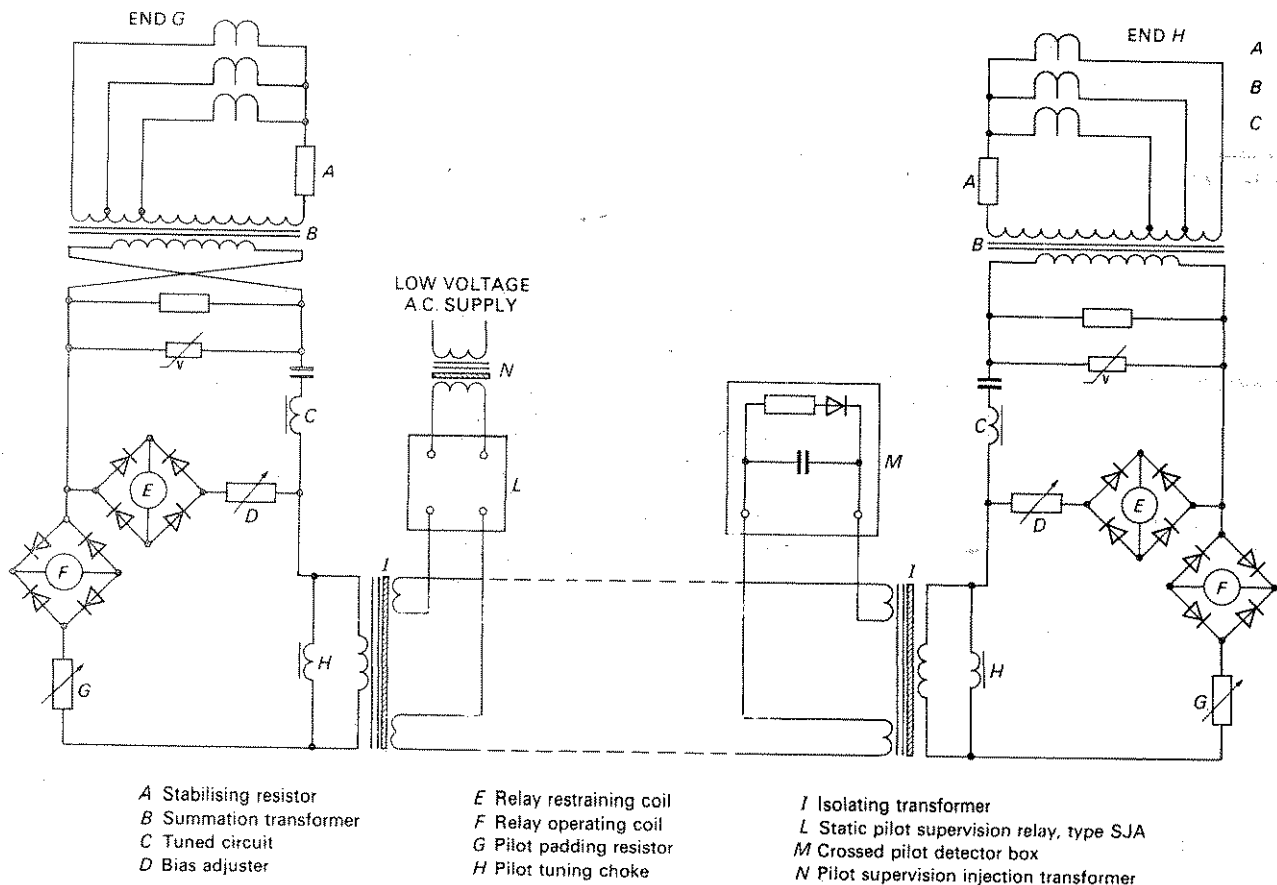


Figure 10.15 Type DS7 feeder protection.

about 180 volts, although at high through-currents the pilot voltage waveform becomes sharply peaked.

The pilot circuit of the relay is insulated to withstand a 5kV test. If a higher induced voltage is anticipated, isolating transformers can be used.

The pilot circuit can be supervised by d.c. injection across a series-connected capacitor.

As mentioned above, the electromechanical Translay system does not trip at both ends of a line for a single end infeed; if this is deemed to matter, intertripping can be carried out by d.c. injection on the protection pilots.

### 10.8.2 Type DS7

This scheme, shown in Figure 10.15, is in the higher speed class. It is also of the balanced voltage type, but differs in its derivation of the reference voltage. An auxiliary summation CT is loaded with a resistive shunt to provide a voltage which is balanced over the pilot circuit with a corresponding quantity at the other end of the zone. The measuring relay is a double-wound moving coil element of the axial motion type, the coils being energized through bridge rectifiers. One coil, connected in series with the pilots, observes any unbalance component; the other coil is connected in series with an adjustable resistance across the reference voltage to provide restraint.

The scheme is suitable for use with pilots of up to 1000 ohms. The pilot loop, not including the relays, is made up to this value by padding rheostats, and the bias rheostat is also adjusted to give the correct degree of restraint according to the length and capacitance of the pilot.

The pilots are compensated where necessary by shunt reactors at each end. Pilot isolating transformers are used

if high induced voltages are expected, and pilot supervision can be applied.

This scheme trips both ends of the circuit even if fault current is fed from one end only.

The standard settings are:

|                                   |               |
|-----------------------------------|---------------|
| Least sensitive earth fault       | 20% of rating |
| Least sensitive phase-phase fault | 40% of rating |
| Three-phase fault                 | 23% of rating |

A variation of this scheme, type DSE7, is sometimes applied to cable circuits having a high value of capacitance. The settings are raised above the standard values, to prevent the in-zone capacitance current causing a trip.

Another version is the type DSF7 system which is generally similar to the type DS7 but uses rotary moving coil measuring elements.

### 10.8.3 Types DSC7 and DSC8

The DSC7 protective system, shown in Figure 10.16, is designed specifically for use with rented telephone-type pilots. In principle it is similar to the DS7 system, but the circuit constants are chosen to meet the parameters and restrictions of this type of pilot circuit.

The main differences are as follows:

- Pilot isolating transformers are avoided and high voltage isolation is provided in the relay and the summation CT.
- The pilot voltage does not exceed the specified limit.
- Pilot supervision and trip check relays are always applied.

The type DSC8 system is basically identical to the DSC7





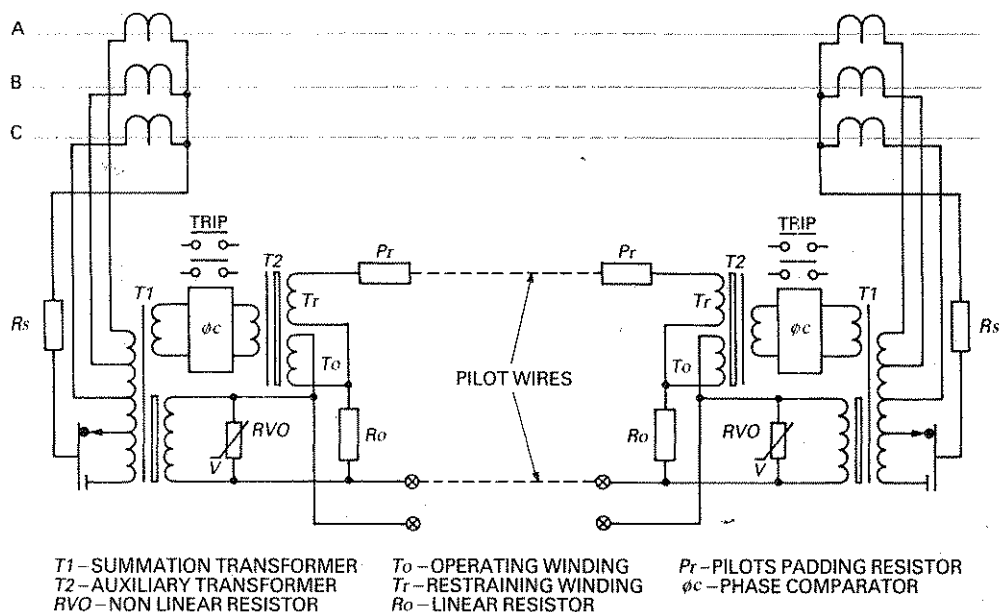


Figure 10.17 Translay S feeder protection circuit diagram.

### 10.8.5

#### Tee'd feeder schemes

The basic Merz-Price principle can be applied to a zone having any number of terminals; the current transformers, pilots and relay can be regarded as an analogue of the primary system. In order that this analogue may be a correct representation, it is necessary that all current transformers have strictly linear output characteristics, a condition which is not observed in two-ended schemes. For tee'd circuit applications linearity is essential. Special schemes are therefore designed to comply with this limitation.

#### Translay system type HOA4 for tee'd circuits

Since it is necessary to maintain linearity in the balancing circuit, though not in the sensing element, the voltage reference is derived from separate quadrature transformers, as shown in Figure 10.18. These are auxiliary units with summation windings energized by the main current transformers in series with the upper electromagnets of the sensing elements. The secondary windings of the quadrature current transformers at all ends are interconnected by the pilots in a series circuit which also includes the lower electromagnets of the relays. Secondary windings on the relay elements are not used, but these elements are fitted with bias loops in the usual way.

The plain feeder Translay settings are increased in the tee'd scheme by 50% for one tee and 75% for two.

#### Type DSB7

This also is a balanced voltage scheme for multi-ended feeder circuits but is aimed at a higher speed of operation. A diagram is shown in Figure 10.19. Summation quadrature transformers are used to provide the analogue quantity, which is balanced in a series loop through a pilot circuit. Separate secondary windings on the quadrature current transformers are connected to full-wave rectifiers, the outputs of which are connected in series in a second pilot loop, so that the electromotive forces summate arithmetically.

The measuring relay is a double-wound moving coil type, one coil being energized from the vectorial summation loop; the other receives bias from the scalar summation in the second loop proportional to the sum of the currents in the several line terminals, the value being adjusted by the inclusion of an appropriate value of resistance.

Since the operating and biasing quantities are both derived by summation, the relays at the different terminals all behave alike, either to operate or to restrain as appropriate.

Special features are included to ensure stability, both in the presence of transformer inrush current flowing through the feeder zone and also with a 2—1—1 distribution of fault current caused by a short circuit on the secondary side of a star-delta transformer.

Typical performance is as follows:

Least sensitive earth fault setting 33% of rating.

Least sensitive phase-phase fault setting 100% of rating.

Three-phase fault setting 58% of rating.

Designed stability level is 30 times rating (due to the range of linearity of the quadrature current transformers).

Operating time at 5 times setting 90 milliseconds.

### 10.9

#### CARRIER SYSTEMS

In the previous sections, the pilots have been treated as an auxiliary wire circuit which interconnects relays at the boundaries of the protected zone. In many circumstances, such as the protection of longer line sections or where the route involves installation difficulties, it is too expensive to provide an auxiliary cable circuit for this purpose, and other means are sought.

A number of communication media exist which can provide facilities for the transfer of information between two relaying points and these are discussed more fully in Chapter 8.

In all cases (apart from private pilots and some short rented pilots) power system frequencies cannot be transmitted directly on the communication medium. Instead a relaying

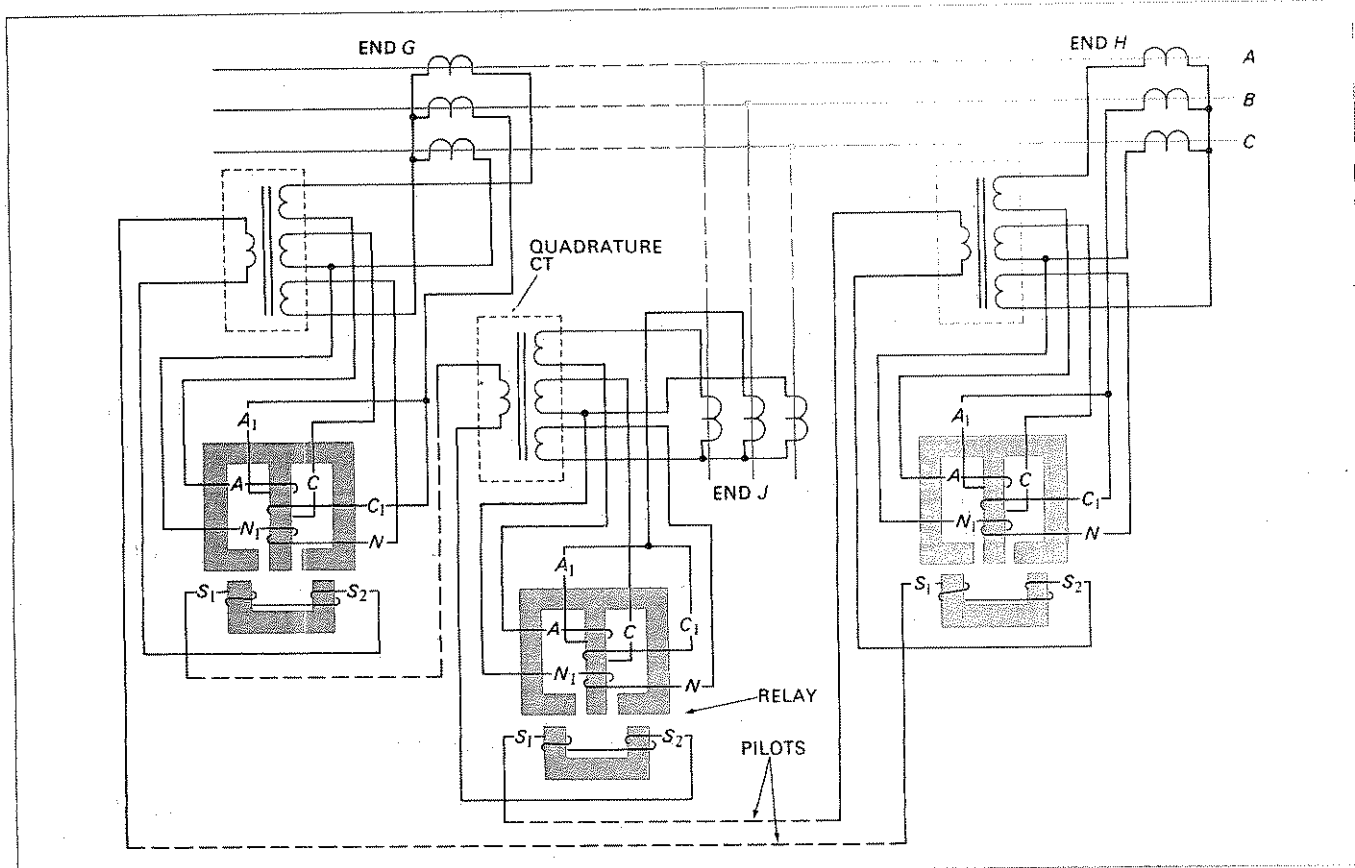


Figure 10.18 Electromechanical Translay relays type HOA4 applied to a three-terminal line.

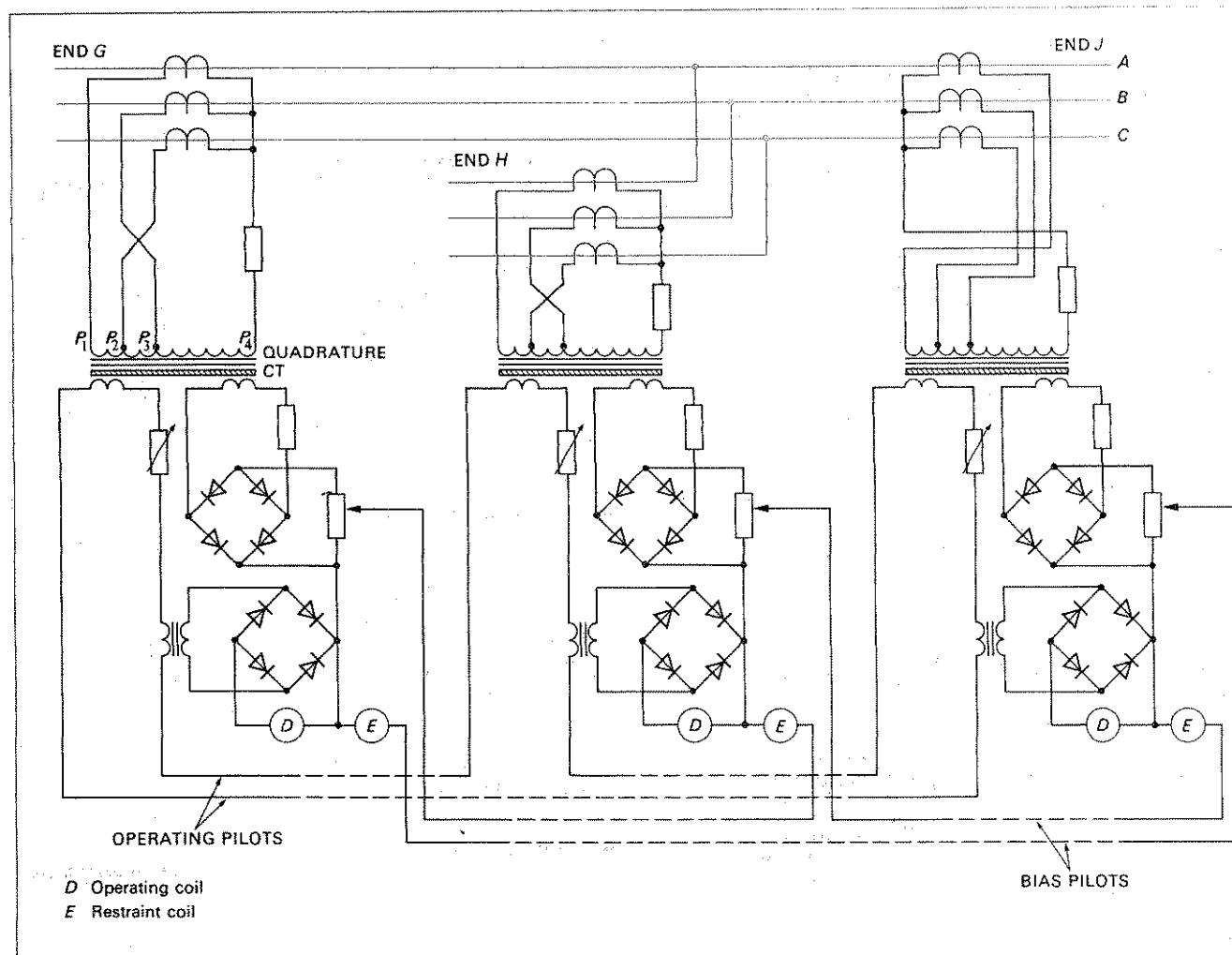


Figure 10.19 Type DSB7 protection applied to a three-ended feeder.

quantity may be used to vary the higher frequency associated with each medium (or the light intensity for fibre-optic systems), and this process is normally referred to as modulation of a carrier wave. Demodulation or detection of the variation at a remote receiver permits the relaying quantity to be reconstituted for use in conjunction with the relaying quantities derived locally, and forms the basis for all carrier systems of unit protection.

The carrier-aided distance schemes described in Chapter 12 and directional comparison schemes utilize protection signalling (see Chapter 8) to transfer blocking, permissive or direct tripping commands between remote relaying points. The protection signalling command takes no part in fault detection or measurement as such, but simply provides additional information from the remote relaying point so that the scheme can be selective to trip only for faults between the relaying points, without excessive delay, regardless of the position of the fault in the feeder. For most faults, the selectivity and independence of fault position of such schemes approximate to the ideal characteristics which are inherent in unit protection schemes such as those based on the principles of Merz and Price. During the more complex conditions such as sequential or spreading faults, current reversals or maintained out-of-zone faults, differences between carrier-aided schemes and unit protection schemes may be more significant.

## 10.10

### CARRIER UNIT PROTECTION SCHEMES

Carrier systems are generally insensitive to induced power system currents since the systems are designed to operate at much higher frequencies, but each medium may be subjected to noise at the carrier frequencies which may interfere with its correct operation. Variations of signal level, restrictions of the bandwidth available for relaying and other characteristics unique to each medium influence the choice of the most appropriate type of scheme.

#### 10.10.1

##### Current differential

The carrier channel is used in this type of scheme to convey both the phase and magnitude of the current at one relaying point to another for comparison with the phase and magnitude of the current at that point.

##### Voice-frequency channels

A voice-frequency carrier signal of say 1800Hz may be used. Frequency modulation (FM) is preferred to amplitude modulation (AM) since it is less sensitive to the noise and variations in signal level which can occur on any telecommunication channel. To give high security against maloperation of the scheme, the receivers usually incorporate circuits which monitor the signal quality, but, in common with the protection signalling equipments described in Chapter 8, the dependability may be correspondingly impaired. Two further characteristics of voice-frequency channels influence the design and performance of current differential schemes:

##### i. Delays

The restricted bandwidth of the channel equipment gives an inherent delay of about 2ms. Though the signal propagation delays for high frequency carrier or optical signals of about 1ms per 300km are small, the delays on loaded pilots of about 1ms per 20km may prove significant. For sensitive relay performance it is normally necessary to compensate for the delay by introducing a similar delay in the locally derived signal before any analogue comparison with the received signal can be permitted. This may be implemented by means of analogue to digital converters, clocked shift registers and digital to analogue converters, in which variation of the clock frequency controls the delay.

##### ii. Dynamic range

Unit protection relays are often required to operate on fault currents of about 0.3 times rating, and remain stable on through fault currents of up to 30 or more times rating. For linear performance of the relays, the carrier channel would have to have a dynamic range of more than 100:1. In practice, using a voice frequency carrier frequency of about 1800Hz, the peak deviations in frequency must be limited to about  $\pm 1200$ Hz, and hence the small deviations corresponding to amplitudes near to the threshold of the relay scheme can be difficult to detect accurately.

Non-linear techniques can be used to make the deviation proportionately larger at low levels of modulation, but the characteristics at both ends must be carefully matched to avoid introducing errors. Some schemes use a restricted dynamic range in which a relatively sensitive comparison of phase and amplitude is possible up to some fault level above which the scheme becomes sensitive to phase shifts alone.

##### Data communication channels

Carrier media such as optical fibres and microwave systems usually operate at very high data rates. Where the terminal equipments utilize the modern digital techniques of Pulse Code Modulation (PCM), data communication channels having data rates of typically 64 kbits/s may be provided in place of voice frequency channels. These give better channel utilization and usually incorporate error checking features.

By use of analogue to digital (A-D) converters the analogue relaying quantity can be sampled and transmitted as a coded message to the remote relay, where the decoded message may be compared with a locally derived signal. By the use of suitable algorithms, digital techniques may be used to carry out the comparison and decision processes in addition to the transfer of data.

Channel synchronization and delay measurements can use 'poll and answer' techniques under software control, whilst the dynamic range can be adequate if A-D converters with sufficient resolution are used in conjunction with a suitably high sampling rate. Further details of current differential relays using data communication channels are provided in Chapter 13.

#### 10.10.2

##### Phase comparison

The carrier channel is used to convey the phase angle of the current at one relaying point to another for comparison with the phase angle of the current at that point.

The principles of phase comparison are illustrated in Figure 10.20. The carrier channel transfers a logic or 'on/off' signal which switches at the zero crossing points of the power frequency waveform. Comparison of a local logic signal with the corresponding signal from the remote end provides the basis for the measurement of phase shift between power system currents at the two ends and hence discrimination between internal and through faults.

Load or through fault currents at the two ends of a protected feeder are in antiphase (using the normal relay convention for direction), whilst during an internal fault the (conventional) currents tend towards the in-phase condition. Hence, if the phase relationship of through fault currents is taken as a reference condition, internal faults cause a phase shift of approximately  $180^\circ$  with respect to the reference condition.

Phase comparison schemes respond to any phase shifts from the reference conditions, but tripping is usually permitted only when the phase shift exceeds an angle of typically 30 to 90 degrees, determined by the time delay setting of the measurement circuit, and this angle is usually referred to as the Stability Angle. Figure 10.21 is a polar

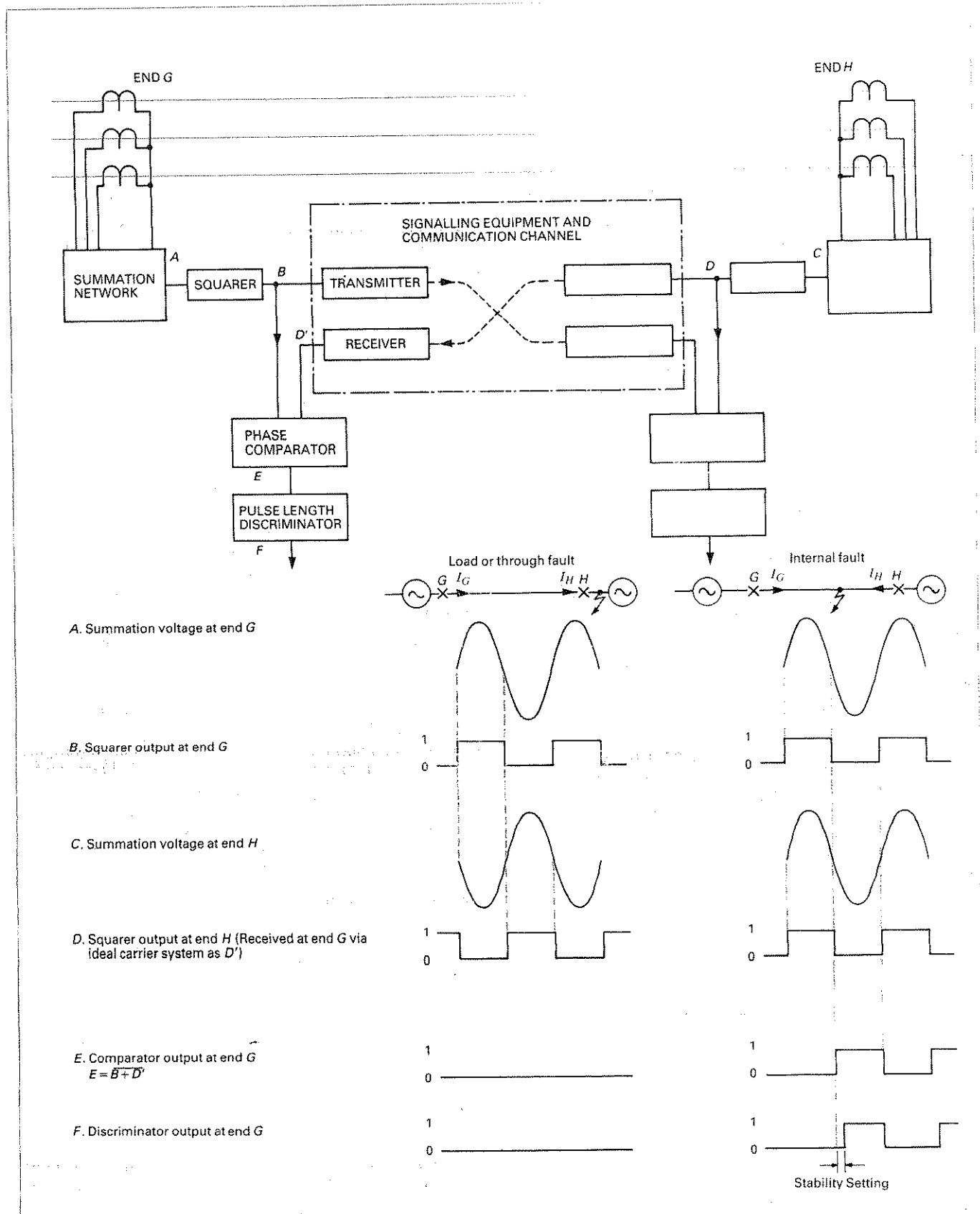


Figure 10.20 Principles of phase comparison protection.

diagram which illustrates the discrimination characteristics which result from the measurement techniques used in phase comparison schemes.

Since the carrier channel is required to transfer only binary information, the techniques associated with sending teleprotection commands described in Chapter 8 are appropriate. Blocking or permissive trip modes of operation are possible, however Figure 10.20 illustrates the more

usual blocking mode, since the comparator provides an output when neither squarer is at logic '1'. A permissive trip scheme can be realized if the comparator is arranged to give an output when both squarers are at logic '1'. Performance of the scheme during failure or disturbance of the carrier channel and its ability to clear single-end-fed faults depends on the mode of operation, the type and function of fault detectors or starting units, and the use of any

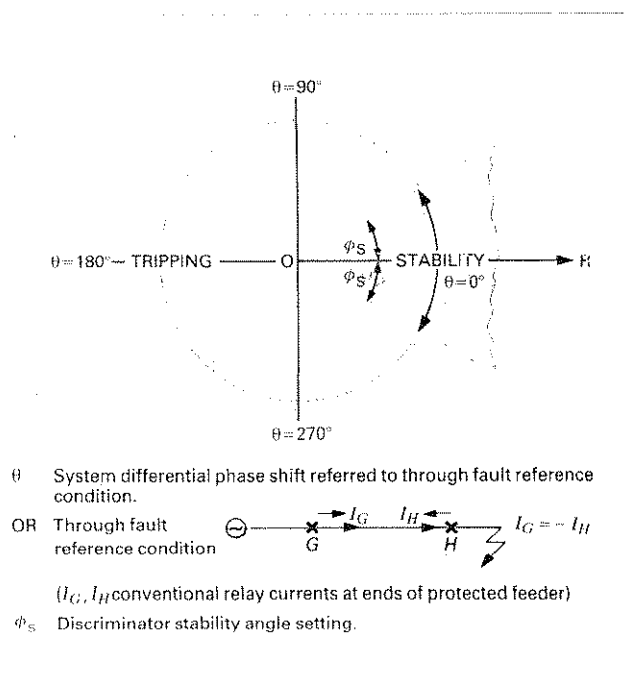


Figure 10.21 Phase comparison relay system discrimination characteristics.

additional signals or codes for channel monitoring and transfer tripping.

### Voice frequency channels

Binary information from the squarer output is usually transferred by using frequency shift keying (FSK). In contrast to the FM used for current differential schemes, FSK uses two discrete frequencies, usually about 200 Hz apart, at about the middle of the voice band. This arrangement can readily be made insensitive to small variations of frequency due to noise and because of the restricted (and fixed) deviation the FSK system is less sensitive to variations in delay or frequency response which are often encountered at the extreme edges of voice frequency bands.

Blocking or permissive trip modes of operation may be implemented. In addition to the two frequencies used for conveying the squarer information, a third tone is often used either for channel monitoring or transfer tripping dependent on the scheme.

For a sensitive phase comparison scheme, accurate compensation for channel delay is required. However, since both the local and remote signals are logic pulses, simple time delay circuits can be used, in contrast to the analogue delay circuitry usually required for current differential schemes.

### Power line carrier channels

Historically, 'on/off' keying of a power line carrier frequency was the method exploited in the invention of the phase comparison technique. The principles of the scheme are illustrated in Figure 10.22.

The scheme operates in the blocking mode. The 'squarer' logic is used directly to turn a transmitter 'on' or 'off' at one end, and the resultant burst (or block) of carrier is coupled to and propagates along the power line which is being protected to a receiver at the other end. Carrier signals above a threshold are detected by the receiver, and hence produce a logic signal corresponding to the block of carrier. In contrast to Figure 10.20, the signalling system is a 2 wire rather than 4 wire arrangement, in which the local transmission is fed directly to the local receiver along with any received signal. The transmitter frequencies at both ends are nominally equal, so the receiver responds equally to blocks of carrier from either end. Through-fault current

results in transmission of blocks of carrier from both ends, each lasting for half a cycle, but with a phase displacement of half a cycle, so that the composite signal is continuously above the threshold level and the detector output logic is continuously '1'. Any phase shift relative to the through fault condition produces a gap in the composite carrier signal and hence a corresponding '0' logic level from the detector. The duration of the logic '0' provides the basis for discrimination between internal and external faults, tripping being permitted only when a time delay setting is exceeded. This delay is usually expressed in terms of the corresponding phase shift in degrees at system frequency,  $\phi_S$  in Figure 10.21.

The advantages generally associated with the use of the power line as the communication medium apply namely, that a power line provides a robust, reliable, and low-loss interconnection between the relaying points. In addition dedicated 'on/off' signalling is particularly suited for use in phase comparison schemes as follows:

#### Blocking mode operation

Since reliable reception of carrier signals is required only during external faults, no allowance need be made for the attenuation of signal which often accompanies an internal fault. In contrast to permissive or direct tripping schemes, high power output or boosting is not required to overcome the extra attenuation.

#### Noise immunity

The digital techniques of 'on/off' keying of the transmitter, and use of a receiver which detects the presence of signal above or below a threshold level, enable high performance to be achieved with much lower power output than is normally associated with power line carrier communication channel (PLCCC) equipment. The whole of the rated transmitter output power is utilized in the protection signal, and the receiver is inherently insensitive to all noise below the threshold level.

Power line carrier (PLC) equipments may be subjected to noise from a number of causes. Continuous broadband noise is produced from corona discharge between the high voltage conductors whilst other PLC equipment and radio transmitters produce unwanted frequencies. By the choice of suitable operating frequencies and receiver selectivity, all noise other than a restricted bandwidth of corona noise is avoided or rejected. For 'on/off' keyed systems, performance will be unaffected so long as the effective noise level is below the threshold of operation. Typical thresholds (or receiver sensitivities) are about 1 V r.m.s. (or +12 dBm where 0 dBm = 1 mW on 75 ohms) whereas the worst noise levels, which are associated with the highest system voltages, longest lines and lowest operating frequencies during foul weather, seldom exceed -10 dBm when measured in a typical phase comparison receiver bandwidth of about 2 kHz. The safety margin of +12 dBm to -10 dBm, that is 22 dB, ensures that no false operation of the receiver occurs and the scheme is therefore very dependable.

Much higher levels of noise can occur as a result of lightning strikes or system fault inception or clearance, but these are usually of short duration and so cause negligible delays in tripping, even if the receiver is falsely operated momentarily. The most severe noise is produced by the operation of the circuit isolators, where the weak ionization of the arc results in repeated restriking, lasting some seconds. This produces high-amplitude trains of high frequency oscillations which are readily passed to the PLC equipment via the coupling gear and so in the unlikely event of a coincidental internal fault, delayed tripping might occur. In general, high levels of noise tend to operate the receiver or aid the blocking signals so that the stability of the scheme on through faults is assured.

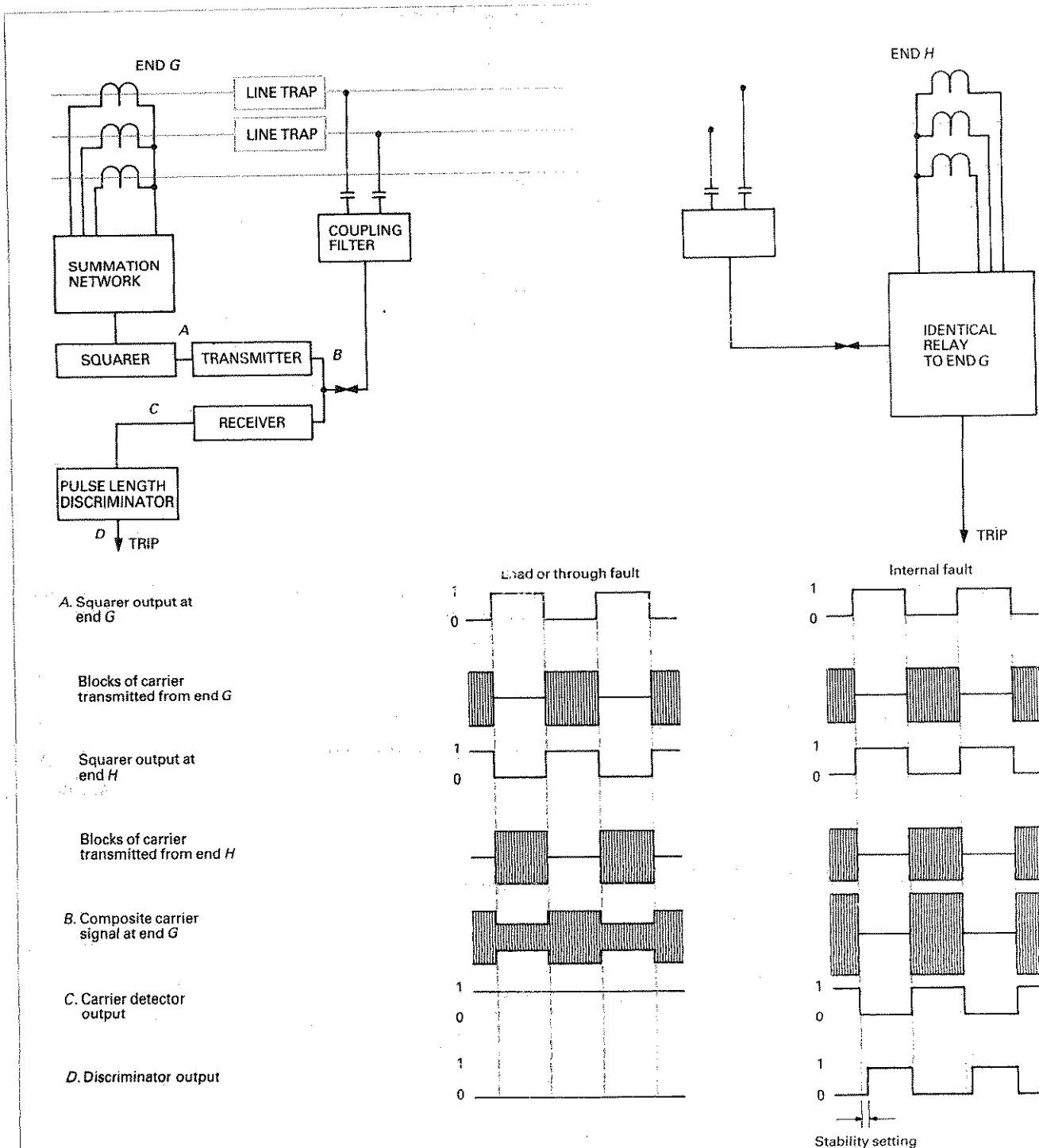


Figure 10.22 Principles of power line carrier phase comparison.

#### Channel delays

Systems using 'on/off' modulation of a power line carrier frequency can readily achieve operating times of less than 1ms. Most of the delay is associated with the restricted bandwidth of the receiver filter rather than the detection process itself. For blocking mode operation, no deliberate (or security) delays need be incorporated and the detector may respond in say 2 cycles at a carrier frequency of 100kHz giving an operating time of only about 20 microseconds.

The two-wire connection of the system inherently removes most of the need for delay compensation required on four-wire systems. Since both the local and remote signals are applied to the same receiver, both are subjected to similar delays so that any differential phase shifts between the transmissions are accurately reproduced. Calibration and

testing of the discriminator setting can be performed on a single-ended basis. The accuracy of the signalling and measurement system is normally such that very little allowance for error need be built into the discriminator setting, although due allowance must be made for the carrier propagation delay of about 1ms per 300km on the longer lines. In this way small angular settings can be realized, giving the highest sensitivity and dependability of the scheme for all internal faults.

#### Dedicated communication channel

Since the 'on/off' keyed carrier channel is normally dedicated entirely to the requirements of the phase comparison scheme, it is usually combined with the associated power system relaying equipment in a single assembly. The performance of the resultant scheme can be fully specified

and tested without reference to any other signalling equipment. Operationally, apart from the coupling gear which may be shared with PLCCC equipment, the phase comparison protection relay scheme is therefore substantially independent of the standards and procedures adopted in the telecommunications department.

### Stability angle

The stability angle setting must ensure that instability cannot occur under any load or through-fault conditions, and must therefore allow for any errors in the system which produce real or apparent differential phase shifts.

#### i. CT phase errors

These are usually small, and where similar CT's are used at the two ends the differential error is usually neglected.

#### ii. Propagation delays

PLC signals propagate at about the speed of light (300km/ms), and therefore produce an apparent phase shift of approximately  $1^\circ$  per 17km of line length (at 50Hz). Current also propagates at a similar speed.

For the longer lines the propagation delays are significant and must be allowed for in the stability angle setting.

#### iii. Capacitance current

The distributed capacitance associated with any transmission line causes a capacitive current to flow into the line from any energizing source. Since this current is in addition to the load current which flows out of the line, and typically leads it by more than  $90^\circ$ , significant differential phase shifts between the currents at the ends of the line can occur, particularly when load current is low.

The system differential phase shift may encroach into the tripping region of the simple discriminator characteristic.

regardless of how large the stability angle setting may be. Figure 10.23 illustrates the effect and indicates techniques which are commonly used to ensure stability.

Operation of the discriminator can be permitted only when current is above some threshold, so that measurement of the large differential phase shifts which occur near the origin of the polar diagram is avoided. By choice of a suitable threshold and stability angle, a 'keyhole' characteristic can be provided such that the capacitive current characteristic falls within the resultant stability region. Fast resetting of the fault detector is required to ensure stability following the clearance of a through fault when the currents tend to fall towards the origin of the polar diagram.

The mark-space ratio of the squarer (or modulating) waveform can be made dependent on the current amplitude. Any decrease in the mark-space ratio will permit a corresponding differential phase shift to occur between the currents before any output is given from the comparator for measurement in the discriminator. A squarer circuit with an offset or bias can provide a decreasing mark-space ratio at low currents, and with a suitable threshold level the extra phase shift  $\theta_C$  which is permitted can be arranged to equal or exceed the phase shift due to capacitive current. At high current levels the capacitive current compensation falls towards zero and the resultant stability region on the polar diagram is usually smaller than on the keyhole characteristic, giving improvements in sensitivity and/or dependability of the scheme. Since the stability region encompasses all through fault currents, the resetting speed of any fault detectors or starters (which may still be required for other purposes, such as the control of a normally quiescent scheme) is much less critical than with the keyhole characteristic.

### System tripping angles

For the protection scheme to trip correctly on internal faults the change in differential phase shift,  $\theta_0$ , from the through fault condition taken as reference, must exceed the effective stability angle of the scheme. Hence:

$$\theta_0 \geq \phi_s + \theta_C \quad \dots \text{Equation 10.9}$$

Where  $\phi_s$  = stability angle setting

$\theta_C$  = capacitive current compensation (when applicable)

The currents at the ends of a transmission line  $I_G$  and  $I_H$  may be expressed in terms of magnitude and phase shift  $\theta$  with respect a common system voltage.

$$I_G = |I_G| \angle \theta_G$$

$$I_H = |I_H| \angle \theta_H$$

Using the relay convention described in Section 10.2, the reference through fault condition is

$$I_G = -I_H$$

$$\therefore I_G \angle \theta_G = -I_H \angle \theta_H = I_H \angle \theta_H \pm 180^\circ$$

$$\therefore |\theta_G - \theta_H| = 180^\circ$$

During internal faults, the system tripping angle  $\theta_0$  is the differential phase shift relative to the reference condition.

$$\therefore \theta_0 = 180 - |\theta_G - \theta_H|$$

Substituting  $\theta_0$  in equation 10.9, the conditions for tripping are:

$$180 - |\theta_G - \theta_H| \geq \phi_s + \theta_C$$

$$\therefore |\theta_G - \theta_H| \leq 180 - (\phi_s + \theta_C) \quad \dots \text{Equation 10.10}$$

The term  $(\phi_s + \theta_C)$  is the effective stability angle setting of the scheme. Substituting a typical value of  $60^\circ$  in Equation 10.10 gives the tripping condition as

$$|\theta_G - \theta_H| \leq 120^\circ \quad \dots \text{Equation 10.11}$$

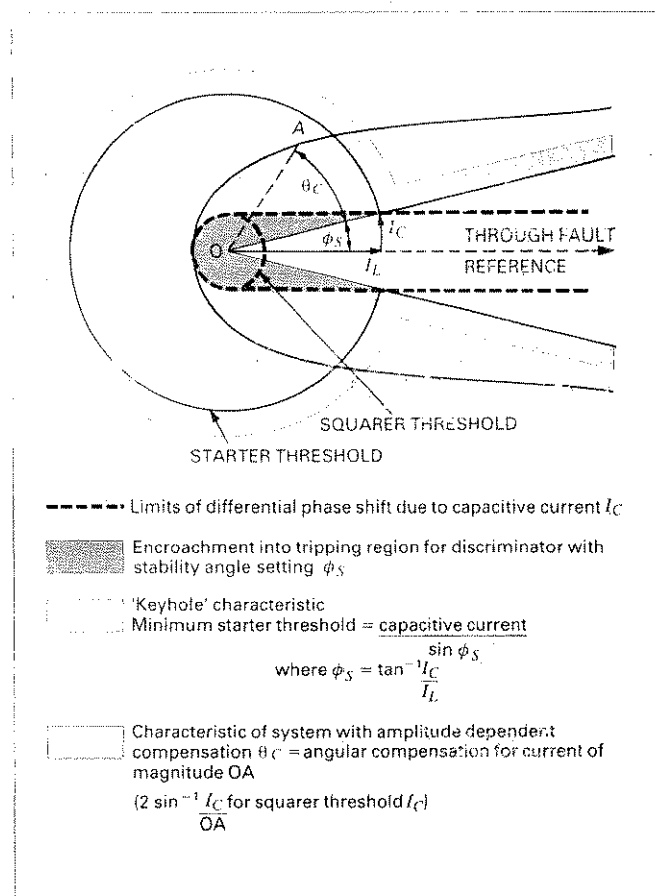


Figure 10.23 Capacitive current in phase comparison schemes and techniques used to avoid instability



In the absence of pre-fault load current, the voltages at the two ends of a line are in phase. Internal faults are fed from both ends with fault contributions whose magnitudes and angles are determined by the position of the fault and the system source impedances. Although the magnitudes may be markedly different, the angles (line plus source) are similar and seldom differ by more than about  $20^\circ$ .

Hence  $|\theta_G - \theta_H| \leq 20^\circ$  and the requirements of Equation 10.11 are very easily satisfied. The addition of arc or fault resistance makes no difference to the reasoning above, so the scheme is inherently capable of clearing such faults.

### Effect of load current

When a line is heavily loaded prior to a fault the e.m.f.'s of the sources which cause the fault current to flow may be displaced by up to about  $50^\circ$ , that is, the power system stability limit. To this the differential line and source angles of up to  $20^\circ$  mentioned above need to be added.

So  $|\theta_G - \theta_H| \leq 70^\circ$  and the requirements of Equation 10.11 are still easily satisfied.

For three phase faults, or solid earth faults on phase-cy-phase comparison schemes, through load current falls to zero during the fault and so need not be considered. For all other faults, load current continues to flow in the healthy phases and may therefore tend to increase  $|\theta_G - \theta_H|$  towards the through fault reference value. For low resistance faults the fault current usually far exceeds the load current and so has little effect. High resistance faults or the presence of a weak source at one end can prove more difficult, but high performance is still possible if the modulating quantity is chosen with care and/or fault detectors are added.

### Modulating quantity

Phase-by-phase comparison schemes usually use phase current for modulation of the carrier. Load and fault currents are almost in antiphase at an end with a weak source. Correct performance is possible only when fault current exceeds load current, or

$$\text{for } I_F < I_L, |\theta_G - \theta_H| \approx 180^\circ$$

$$\text{for } I_F > I_L, |\theta_G - \theta_H| \approx 0^\circ \quad \therefore \text{Equation 10.12}$$

where  $I_F$  = fault current contribution from weak source

$I_L$  = load current flowing towards weak source

To avoid any risk of failure to operate, fault detectors with a setting greater than the maximum load current may be applied, but they may limit the sensitivity of scheme. When the fault detector is not operated at one end, fault clearance invariably involves sequential tripping of the circuit breakers.

Most phase comparison schemes use summation techniques to produce a single modulating quantity, responsive to faults on any of the three phases. Phase sequence components are often used and a typical modulating quantity is:

$$I_m = MI_2 + NI_1 \quad \therefore \text{Equation 10.13}$$

where  $I_2$  = Negative phase sequence component

$I_1$  = Positive phase sequence component

$M, N$  = Constants

With the exception of three phase faults all internal faults give rise to negative phase sequence (NPS) currents,  $I_2$ , which are approximately in phase at the ends of the line and therefore could form an ideal modulating quantity. In order to provide a modulating signal during three phase faults, which give rise to positive phase sequence (PPS) currents,  $I_1$ , only, a practical modulating quantity must include some response to  $I_1$  in addition to  $I_2$ .

Typical values of the ratio  $M:N$  exceed 5:1, so that the

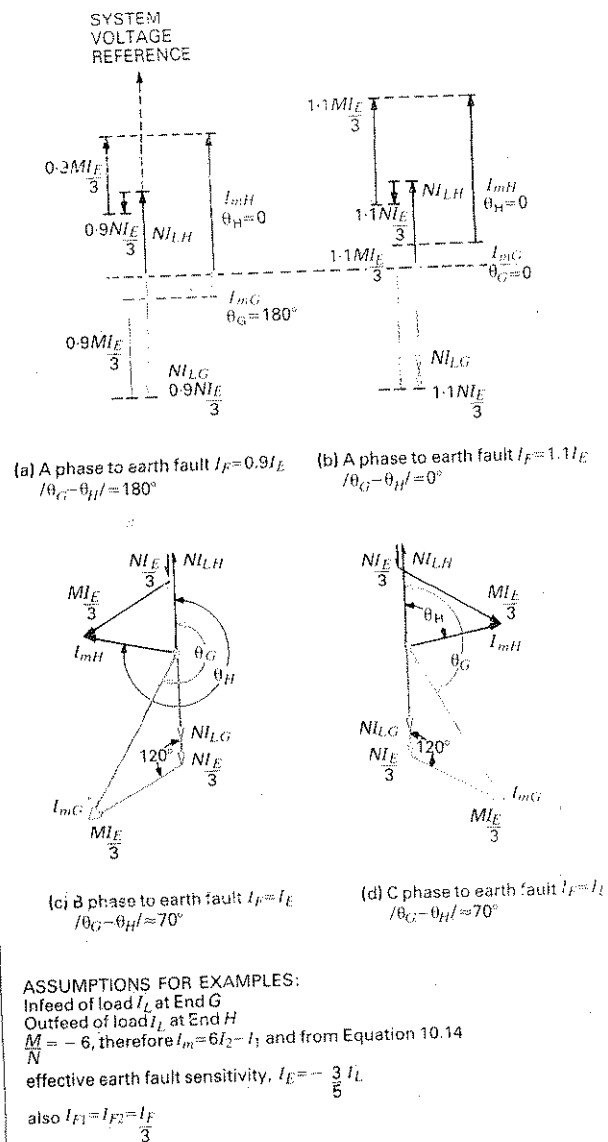


Figure 10.24 Effect of load current on the differential phase shift  $|\theta_G - \theta_H|$  for resistive earth faults at the effective earth fault sensitivity  $I_E$ .

modulating quantity is weighted heavily in favour of NPS, and any PPS associated with load current tends to be swamped out on all but the highest resistance faults.

For a high resistance phase-earth fault, the system remains well balanced so that load current  $I_L$  is entirely positive sequence. The fault contribution  $I_F$  provides equal parts of positive, negative and zero sequence components  $\frac{I_F}{3}$ .

Assuming the fault is on 'A' phase and the load is resistive, all sequence components are in phase at the infeed end G.

$$\therefore I_{mG} = NI_L + \frac{MI_{FG}}{3} + \frac{NI_{FG}}{3} \text{ and } \theta_G \approx 0$$

At the outfeed end load current is negative,

$$\therefore I_{mH} = -NI_L + \frac{MI_{FH}}{3} + \frac{NI_{FH}}{3}$$

$$\text{for } I_{mH} > 0, \theta_H \approx 0 \therefore |\theta_G - \theta_H| = 0^\circ$$

$$\text{for } I_{mH} < 0, \theta_H \approx 180^\circ \therefore |\theta_G - \theta_H| = 180^\circ$$

Hence for correct operation  $I_{mH}$  must be  $\geq 0$

let  $I_{mH} = 0$

$$\text{then } I_{FH} = \frac{3I_L}{\left(\frac{M}{N} + 1\right)} = I_E \quad \text{...Equation 10.14}$$

The fault current in Equation 10.14 is the effective earth fault sensitivity  $I_E$  of the scheme. For the typical values of  $M = 6$  and  $N = -1$ ,  $\frac{M}{N} = -6$

$$\therefore I_E = -\frac{3}{5} I_L$$

Comparing this with Equation 10.12, a scheme using the summation is potentially  $\frac{5}{3}$  times more sensitive than a scheme using phase current for modulation.

Even though the use of a negative value of  $\frac{M}{N}$  gives a lower value of  $I_E$  than if it were positive, it is usually preferred since the limiting condition of  $I_m = 0$  then applies at the load infeed end. Load and fault components are additive at the outfeed end so that a correct modulating quantity occurs there, even with the lowest fault levels. For operation of the scheme it is sufficient therefore that the fault current contribution from the load infeed end exceeds the effective setting.

For faults on B or C phases, the NPS components are displaced by  $120^\circ$  or  $240^\circ$  with respect to the PPS components. No simple cancellation can occur, but instead a phase displacement is introduced. For tripping to occur, Equation 10.10 must be satisfied, and to achieve high dependability under these marginal conditions, a small effective stability angle is essential. Figure 10.24 illustrates operation near to the limits of earth fault sensitivity.

Very sensitive schemes may be implemented by using high values of  $\frac{M}{N}$ , but the scheme then becomes more sensitive to differential errors in NPS currents such as the unbalanced components of capacitive current or spill from partially saturated CT's.

Techniques such as capacitive current compensation and reduction of  $\frac{M}{N}$  at high fault levels may be required to ensure stability of the scheme.

### Fault detection and starting

For a scheme using a carrier system which continuously transmits the modulating quantity, protecting an ideal line (capacitive current = 0) in an interconnected transmission system, measurement of current magnitude might be unnecessary. In practice, fault detector or starting elements are invariably provided and the scheme then becomes a permissive tripping scheme in which both the fault detector and the discriminator must operate to provide a trip output, and the sensitivity of the scheme may be limited by the fault detector. Requirements for the fault detectors vary according to the type of carrier channel used, mode of operation used in the phase angle measurement, that is, blocking or permissive, and the features used to provide tolerance to capacitive current.

#### i. Normally quiescent power line carrier (blocking mode).

To ensure stability on through faults, it is essential that carrier transmission starts before any measurement of the width of the gap is permitted. To allow for equipment tolerances and the difference in magnitude of the two currents due to capacitive current two starting elements are used, usually referred to as 'Low Set' and 'High Set' respectively. Low Set controls the start-up of transmission

whilst High Set, having a setting typically 1.5 to 2 times that of the Low Set element, permits the phase angle measurement to proceed.

The use of impulse starters which respond to the change in current level enables sensitivities of less than rated current to be achieved. Resetting of the starters occurs naturally after a dwell time or at the clearance of the fault. Dwell times and resetting characteristics must ensure that during through faults, a High Set is never operated when a Low Set has reset, and potential race conditions are often avoided by the transmission of an unmodulated (and therefore blocking) carrier for a short time following the reset of low set; this feature is often referred to as 'Marginal Guard'.

#### ii. Scheme without capacitive current compensation

The 'keyhole' discrimination characteristic depends on the inclusion of a fault detector to ensure that no measurements of phase angle can occur at low current levels, when the capacitive current might cause large phase shifts. Resetting must be very fast to ensure stability following the shedding of through load.

#### iii. Scheme with capacitive current compensation (blocking mode).

When the magnitude of the modulating quantity is less than the threshold of the squarer, transmission if it occurred, would be a continuous blocking signal. This might occur at an end with a weak source, remote from a fault close to a strong source. A fault detector is required to permit transmission only when the current exceeds the modulator threshold by some multiple (typically about 2 times) so that the effective stability angle is not excessive. For PLC schemes, the low set element referred to in (i) is usually used for this purpose. If the fault current is insufficient to operate the fault detector, circuit breaker tripping will normally occur sequentially.

#### Fault detector operating quantities

Most faults cause an increase in the corresponding phase current(s) so measurement of current increase could form the basis for fault detection. However, when a line is heavily loaded and has a low fault level at the outfeed end, some faults can be accompanied by a fall in current, which would lead to failure of such fault detection, resulting in sequential tripping (for blocking mode schemes) or no tripping (for permissive schemes). Although fault detectors can be designed to respond to any disturbance (increase or decrease of current), it is more usual to use phase sequence components. All unbalanced faults produce a rise in the NPS components from the zero level associated with balanced load current, whilst balanced faults produce an increase in the PPS components from the load level (except at ends with very low fault level) so that the use of NPS and PPS fault detectors make the scheme sensitive to all faults. For schemes using summation of NPS and PPS components for the modulating quantity, the use of NPS and PPS fault detectors is particularly appropriate since, in addition to any reductions in hardware, the scheme may be characterized entirely in terms of sequence components.

Fault sensitivities  $I_F$  for PPS and NPS impulse starter settings  $I_{1S}$  and  $I_{2S}$ , respectively are as follows:

$$\text{Three phase fault } I_F = I_{1S}$$

$$\text{Phase-phase fault } I_F = \sqrt{3} I_{2S}$$

$$\text{Phase-earth fault } I_F = 3 I_{2S}$$

### 10.11

#### PRACTICAL CARRIER SYSTEM – CONTRAPHASE P10

Contraphase P10 is a phase comparison scheme suitable

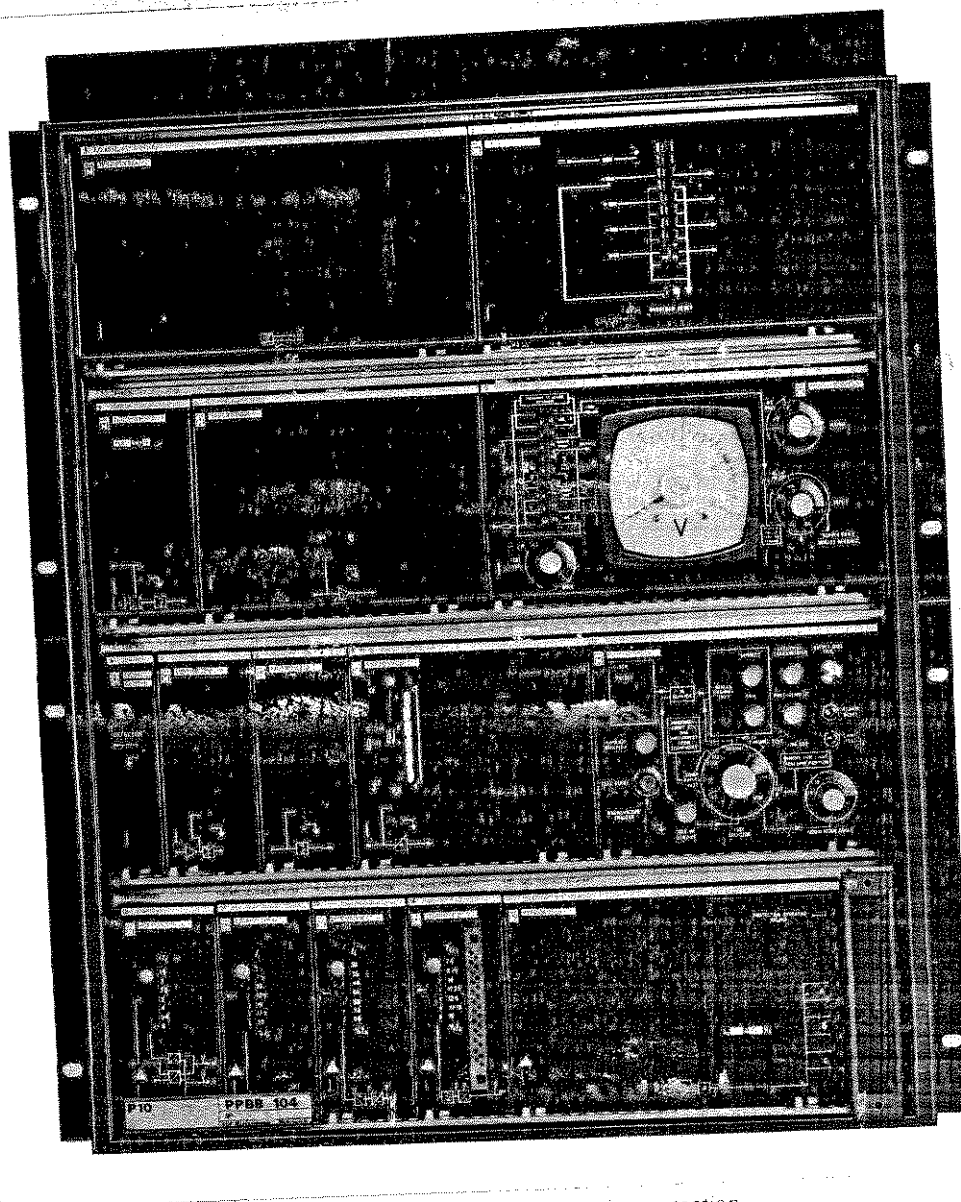


Figure 10.25 Type Contraphase P10 phase comparison carrier protection.

for general application as a main protection on HV and EHV transmission lines. A single normally quiescent 'on/off' modulated power line carrier channel is used for the communication of a modulating signal which is derived from the line currents by the summation of phase sequence components.

The scheme operates in the permissive blocking mode, using phase sequence components for fault detection and the absence of carrier signal for the measurement of phase angle. The operating time is typically between 1 and 2 cycles at both ends of the line, and very high dependability is achieved for high resistance earth faults by the use of a large value of  $M:N$  in the modulating quantity ( $\sim 16$ ) and a small stability angle setting  $\phi_s$  of nominally  $30^\circ$ .

Figure 10.25 shows the modular assembly of P10 which includes the power line carrier transmitter and receiver with comprehensive alarm and test facilities along with the phase sequence networks, starting, measurement and tripping units.

#### 10.11.1

##### Phase sequence networks and starting units

CT secondary current is applied to three separate sequence networks; the first is an NPS network which is unbalanced somewhat to give an output proportional to  $16I_2 - I_1$  for modulation, the second is a PPS network for starting on

balanced (3 phase) faults and the third is an NPS network for starting on unbalanced faults.

##### Modulation

The phase shift due to capacitance current is compensated for automatically by the use of a squaring circuit with an adjustable threshold. Tap settings ( $I_{CIS}$ ) cater for capacitance current  $I_{CI}$  up to 15% of  $I_n$ , so for typical 400kV overhead lines in which the capacitance current is about 0.8A/km (or 0.04% per km when 2000:  $I_n$  CT's are used) line lengths up to 375km can be accommodated.

With capacitance current of 7.5% and load current of 30% of  $I_n$  the total compensation

$$\left( \theta_c = 2 \sin^{-1} \frac{1.3 I_{CIS}}{I_m} \right)$$

is about  $38^\circ$ , giving an effective stability angle ( $\theta_c + \phi_s$ ) of  $68^\circ$ . This exceeds the maximum phase shift due to capacitance current

$$\left( \theta_0 = \tan^{-1} \frac{I_{CIS}}{I_L} \right)$$

of about  $14^\circ$  with a stability safety margin of nominally  $54^\circ$  or  $24^\circ$  minimum if the maximum errors which constitute the choice of  $\phi_s = 30^\circ$  are taken into account. For an internal fault with marginal fault contributions of 30% of  $I_n$  at both

ends, the effective stability angle would be  $68^\circ$  as above. The tripping angle ( $\theta_0 = 180 - |\theta_G - \theta_H|$ ) normally exceeds  $150^\circ$ , hence the typical tripping margin is greater than  $82^\circ$  or  $52^\circ$  if maximum errors of  $30^\circ$  are taken into account.

The effective earth fault sensitivity

$$\left( I_E = \frac{3I_L}{\frac{M}{N} + 1}; \frac{M}{N} = -16 \right)$$

is  $-0.2 I_L$  which for rated load current corresponds to a NPS current of

$$\frac{0.2}{3} \times 100 = 6.7\% \text{ of } I_n$$

Figure 10.26 shows the minimum negative sequence current contribution from an end with low fault level for the extreme condition of a fault at the remote end of typical long lines where the fault level is high. The effective setting of 6.7% ( $I_{H2} = 134\text{A}$  for 2000:1 CT's) might limit the sensitivity of the scheme to the clearance of these faults, on the double circuit line of length 80km, when  $R_f$  is less than only about 30 ohms. However, since  $\frac{M}{N}$  is negative the effective setting applies in practice only to faults on A phase when the end with the low fault level is also the infeed for load current. The provision of earth continuity conductors on the towers for a few kilometres from the end with high fault level will ensure that  $R_f$  is usually less than

30 ohms except for mid-span faults in areas of exceptionally high earth resistivity. If the risk of failure to clear these high resistance (greater than 30 ohms) faults is intolerable, then the NPS fault detector (LS) can be set so that it operates only at end H when the fault contribution exceeds the effective sensitivity. Fault clearance may then involve sequential tripping (end G, then end H) but fault resistances of more than 100 ohms can be tolerated in typical applications.

To ensure stability on heavy through faults when partial saturation of CT's at one end might lead to the generation of NPS spill current, the value of  $\frac{M}{N}$  falls from  $-16$  at  $2I_n$

to a minimum of  $-5$  at high fault levels. Since no compensation can be provided for spill from paralleled CT's on a mesh system, a condition which is particularly likely during through mesh faults, such CT's may have to be excessively large and so CT's on the line itself are usually preferred.

### Balanced faults

Fault detection is by PPS impulse starters having a HS:LS ratio of 2:1. HS settings ( $I_{H2}$ ) are 30 – 60% of  $I_n$ , and the minimum setting can be used for line lengths typically up to about 190km.

For operation the fault contribution to a fault at the remote end of the line, or the increase from the load current for a load infeed end, must exceed the setting. For example, a

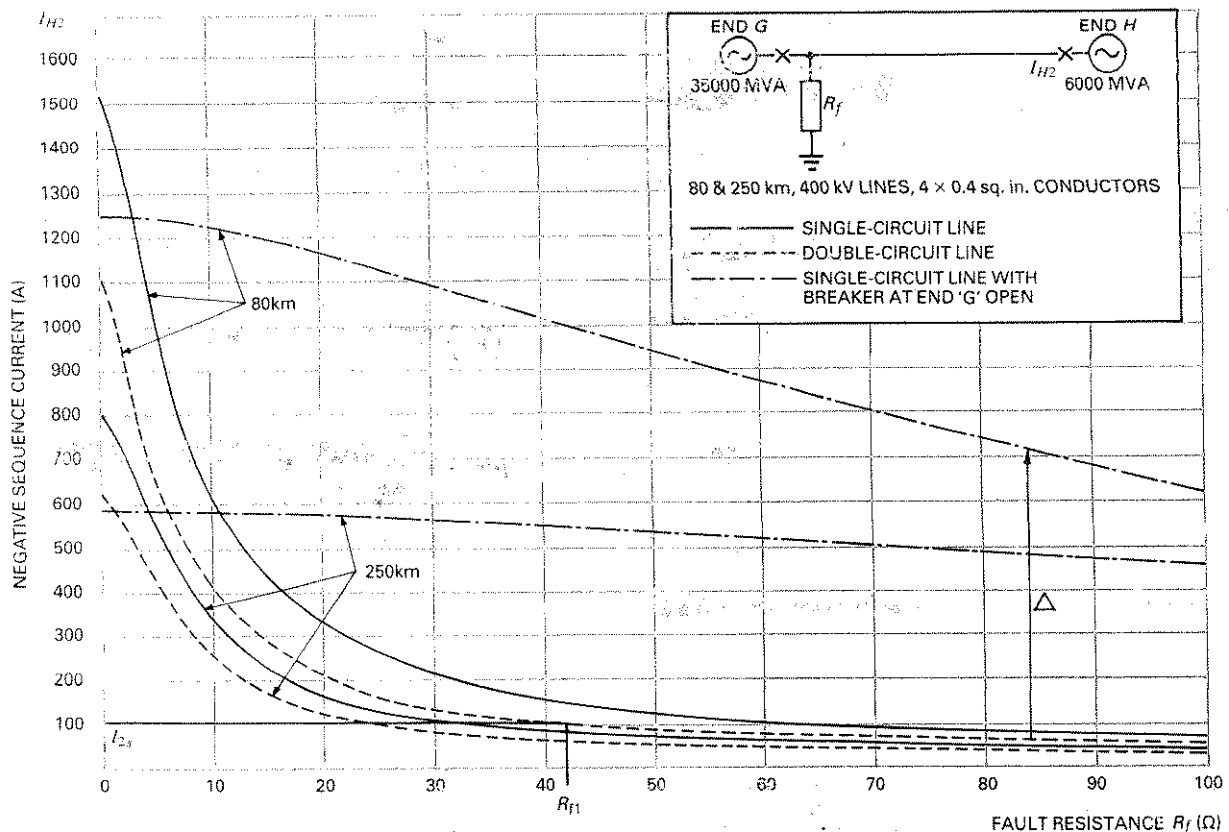


Illustration of the sensitivity of P10 for a typical application on an 80km double-circuit line:  
 $I_{H2}$ : NPS starter setting (5% of  $I_n$  for CT ratio 2000:1)  
 $R_{f1}$ : Maximum fault resistance for simultaneous tripping at both ends. For  $R_f > R_{f1}$ , tripping with sequential.  
 $\Delta$ : Increase in NPS current at end H following trip at end G. End H will trip for  $\Delta > I_{H2}$ , corresponding to  $R_f > 100$  ohms.

Figure 10.26 Negative phase sequence current at an end with low fault level against the fault resistance in a phase-to-earth fault at the remote end of a line where the fault level is high.

fault level of 6000 MVA is more than adequate for most applications on 400kV systems.

### Unbalanced faults

Fault detection is by NPS starters having a HS:LS ratio of 1.5:1. Impulse starter HS settings ( $I_{2s}$ ) are 5–20% of  $I_n$ , whilst non-impulse starting is available at multiples ( $\times I_{2s}$ ) of 1.5–8 times  $I_{2s}$ . The minimum setting of 5% may be used for line lengths up to about 100km so long as the power system is normally interconnected and the line has regular transpositions.

$I_{2s} = 5\%$  gives Ph – Ph fault sensitivity  $\sqrt{3} \times 5 = 8.7\%$  of  $I_n$

and Ph – E fault sensitivity  $3 \times 5 = 15\%$  of  $I_n$ .

When the starter setting is determined by the effective earth fault sensitivity discussed above, then  $I_{2s}$  must be greater than  $0.5I_E$ . Hence for  $I_L = I_n$ ,  $I_{2s} \geq 10\%$  of  $I_n$ .

Figure 10.26 illustrates the performance of the scheme on typical systems with the fault at the least advantageous position. Apart from faults in the last few km of the line, simultaneous tripping for fault resistances up to about 150 ohms would be expected.

The non-impulse starter provides back-up to ensure that tripping takes place in the unlikely event that an internal, resistive earth fault occurs just after the clearance of an external phase/phase fault, when the impulse starter may be relatively insensitive. These conditions can occur on double circuit lines when debris or ionization spreads from one circuit to the other. The maximum duration of carrier transmission is set by the Excessive Transmission Alarm time setting which is usually 10 seconds. After this time limit any further carrier transmission is prevented by suppression of the transmitter, and an alarm is given. To avoid this condition which introduces a possibility of unselective tripping, the non-impulse starter setting is chosen so that it does not operate on the maximum load or through fault NPS current ( $I_{L2}$ ) which might last longer than 10 seconds. For  $I_{L2} = 10\%$  a typical setting would be 20%, provided by  $I_{2s} = 5\%$  and  $\times I_{2s} = 4$ .

### Muting and transfer tripping

Following a trip, carrier transmission is automatically cut-off or muted. This tends to speed up the clearance at the second line end since any blocking influence from the first end is removed.

Carrier may be muted by operation of an external relay contact, so that the scheme may be de-stabilized. Faults between a breaker and line CT appear as an out-of-zone fault to the P10 line protection. To remove the fault contribution from the remote end the scheme may be de-stabilized by the local busbar protection, giving a transfer trip at the remote end. Similarly, in the case of breaker failure, de-stabilizing can be used to implement a back-tripping scheme. In both cases the scheme is permissive, hence for successful operation, the P10 High Set starter must have operated, invariably the case for typical applications, and de-stabilizing must occur within the starter dwell time of nominally 500ms.

#### 10.11.2

### Power line carrier transmitter and receiver

The two-wire normally-quiescent system is capable of operation at any power line carrier frequency between 50kHz and 700kHz. Nominal transmitter output power is 10W into 75 ohms.

### Range

The output power is +40dBm (relative to 1mW on 75 ohms), so with the most sensitive receiver setting of +1dBm, the maximum gross range is 39dB. Typical losses in the combining filters supplied as part of P10 are 2.5dB

per end, whilst coupling losses are typically less than 6dB per end, leaving at least  $39 - 2(2.5 + 6) = 22\text{dB}$  for line loss and a safety margin. A margin of 9dB is recommended, hence 13dB may be allocated to line loss.

When the optimum coupling arrangement is used, that is, the upper and middle conductor for vertically disposed conductors, typical line losses per km at 500kHz for 132, 275 and 400kV lines are about 0.093, 0.041 and 0.031dB respectively, hence the allocation of 13dB corresponds to line lengths of 140, 317 and 419km. For more normal line lengths, the maximum range is unnecessary and often the receiver may be de-sensitized to give an improved signal/noise ratio.

Icing of the line may increase losses by up to about 3 times the normal, but since losses are approximately proportional to the square root of the carrier frequency, application on long lines is still possible so long as low carrier frequencies are chosen.

Attenuation of carrier in cables is high, and cables used as part of a line may introduce further mismatch losses. Application may be possible for cables up to about 6km.

### Carrier frequency

P10 is supplied with a combining filter so that it may be connected in parallel with other PLC equipment sharing the same coupler. The minimum frequency spacing is normally  $\pm 16\text{kHz}$  from the frequencies used in the parallel system for frequencies up to 304kHz, and  $\pm 28\text{kHz}$  for frequencies above 304kHz.

The selectivity of the receiver provides at least 42dB rejection of unwanted frequencies at  $\pm 4\text{kHz}$  from rated frequency.

The frequency should therefore be chosen so that it is at least 4kHz away from any carrier frequencies on the adjacent or parallel lines. Frequencies may be repeated on the system if the lines are far apart (at least 600km) and/or operating at a different voltage, since transformers provide a high loss to carrier signals.

Application of normally-quiescent carrier is often permitted at frequencies which are barred to PLC equipment which produce a continuous output. Operation of the Excessive Transmission detector eliminates the possibility of significant interference with local telecommunication systems, such as aircraft landing beacons.

### Stability angle

The standard nominal setting is  $30^\circ$ . When operating at the maximum recommended range, the large difference between local and remote signal levels may cause an effective increase to  $40^\circ$ . The setting allows for system errors and propagation delays for lines up to 120km. For longer lines the setting must be increased to allow for propagation delay. For example, for a line of length 270km the nominal setting would be  $50^\circ$ .

### Testing

Automatic reflex channel testing every half hour ensures that the channel operates correctly. Failure is indicated if the receive level exceeds the setting with a safety margin of less than 3dB. The transmissions used in the test are modulated in the normal manner, so in the unlikely event of a fault occurring during the test, tripping is normally unaffected, although for those marginal faults which would normally be cleared by sequential tripping there is a remote chance of a delay of up to 80ms.

During commissioning, test facilities enable the stability angle setting to be checked by a single-end test. Correct CT polarities and the absence of any excessive errors can be confirmed by an on-load double-end test.





# Distance protection

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## 11.1

### INTRODUCTION

With the rapid development of power systems and the large amount of interconnection involved to ensure continuity of supply and good voltage regulation, the problems of combining fast fault clearance with system co-ordination have become very important. To meet these requirements, high speed protective systems, suitable for use with the automatic reclosure of circuit breakers are under continuous development and are already very widely used for the protection of medium and high voltage lines.

Distance protection is a non-unit system of protection offering considerable economic and technical advantages. This form of protection is comparatively simple to apply, is of the high speed class and can provide both primary and back-up facilities in a single scheme. It can easily be modified into a unit system of protection by combining it with a signalling channel; in this form it is eminently suitable for use in association with high speed auto-reclosing for the protection of important transmission lines.

## 11.2

### PRINCIPLES OF DISTANCE RELAYS

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point. Such a relay is described as a distance relay and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur between different line sections.

The basic principle of measurement involves the comparison of the fault current 'seen' by the relay with the voltage at the relaying point; by comparing these two quantities it is possible to determine whether the impedance of the line up to the point of fault is greater than or less than the predetermined reach point impedance. A simple example of how this comparison is made is given in Figure 11.1, using a balanced beam relay. The relay is connected at position *R* and receives a secondary current equivalent to the primary fault current and a secondary voltage equivalent to the product of the fault current and the impedance of the line up to the point of fault.

If the relay is designed so that its operating torque is proportional to the current and its restraining torque proportional to the voltage, then, according to the relative number of ampere-turns applied to each coil, there will be

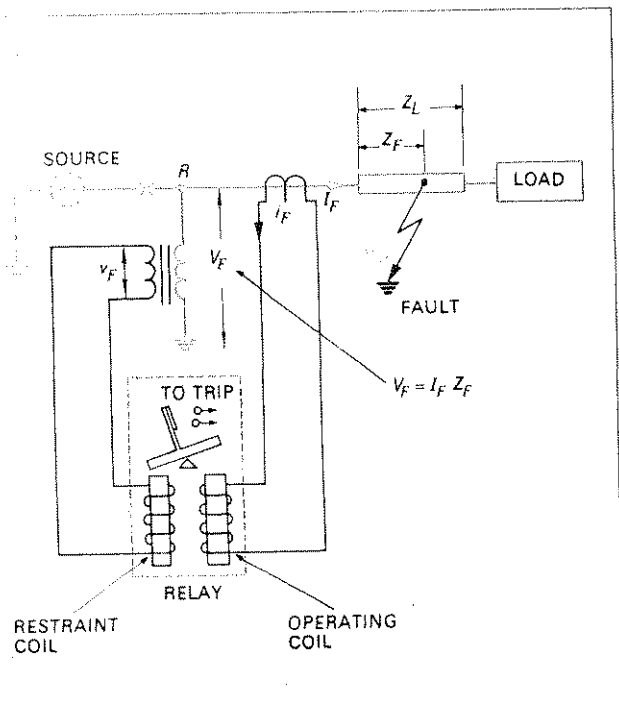


Figure 11.1 Simple impedance relay of the balanced beam type.

a definite ratio of  $V/I$  at which the torques will be equal. This is termed the balance point or reach point setting of the relay.

With such an arrangement, any increase in the current coil ampere-turns without a corresponding increase in the voltage coil ampere-turns will make the relay unbalanced, so that below a given ratio of  $V/I$  the operating torque will become larger than the restraining torque and the relay will close its contacts.

On the other hand, above a given ratio of  $V/I$  the restraining torque will be greater than the operating torque, the relay will restrain and the contacts will remain open.

Such relays have been designed so that it is possible to adjust their ohmic reach setting by changing the relationship of the ampere-turns of the operating coil to those on the restraint coil, making it possible to select a setting suitable for the length of the line to be protected.

The locus of points where the operating and restraining torques are equal is described as the boundary characteristic of the relay and since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an  $R/X$  diagram. The locus of power system impedances such as those of faults, power swings and loads may be plotted on the same diagram and in this manner the performance of the relay in the presence of system disturbances may be studied.

### 11.3

#### RELAY PERFORMANCE

Relay performance is defined in terms of reach accuracy and operating time. Reach accuracy is a comparison of the actual ohmic reach of the relay under practical conditions with the relay setting value in ohms. Reach accuracy depends mainly on the level of voltage presented to the relay under fault conditions.

Operating times vary with fault current, with fault position relative to the relay setting and on the point on the voltage wave at which the fault occurs. It is usual to claim both maximum and minimum operating times. However for modern static distance relays like 'Micromho', the variation between these is small over a wide range of system operating conditions and fault positions.

As both reach accuracy and operating time are functions of

the magnitude of input quantities, it is customary to present information on relay performance by voltage/reach curves, as shown in Figure 11.2, and operating time/fault position curves for various values of system impedance ratios ( $S/R$ s) as shown in Figure 11.3,

where  $S/R = Z_S/Z_L$ .

$Z_S$  = system source impedance behind the relay location.

$Z_L$  = line impedance equivalent to relay reach setting.

Alternatively the above information can be combined in a family of isochronic (or contour) curves, where the fault position expressed as a percentage of the relay setting is plotted against the source to line impedance ratio, as illustrated in Figure 11.4.

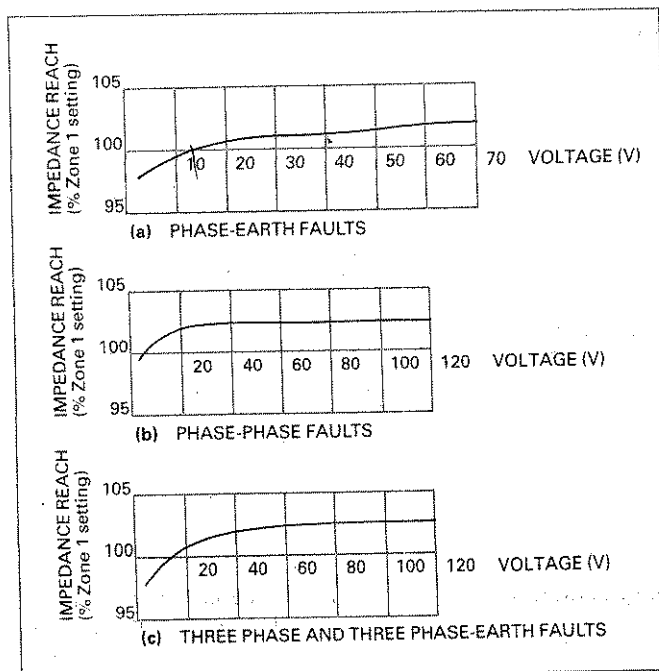


Figure 11.2 Typical impedance reach accuracy characteristics for Zone 1.

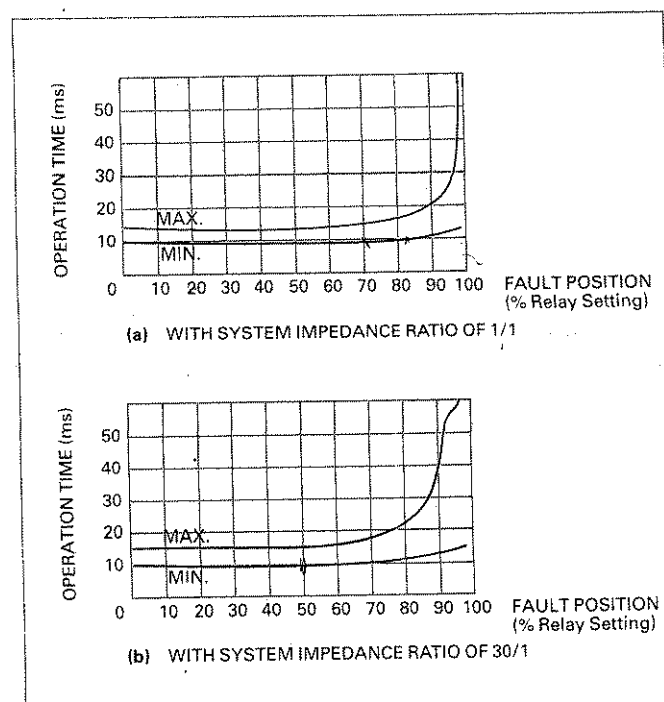
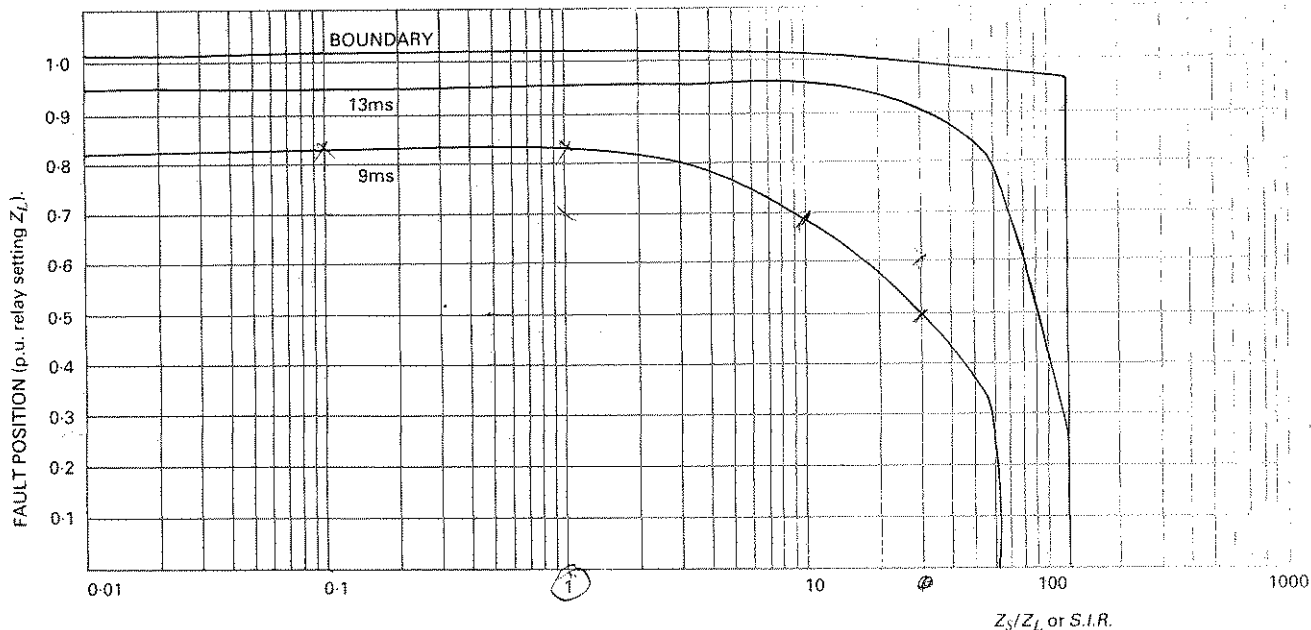
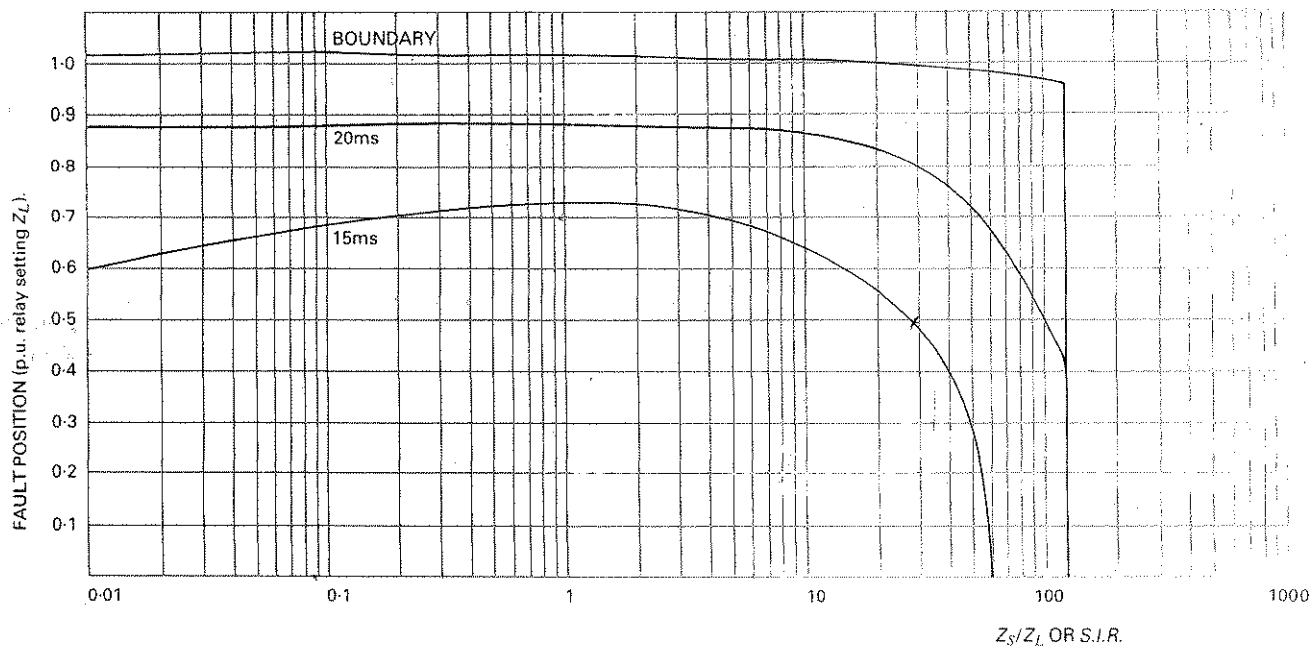


Figure 11.3 Typical operation time characteristics for Zone 1 phase-phase faults.





(a) ZONE 1 PHASE-PHASE FAULT: MINIMUM OPERATION TIMES



(b) ZONE 1 PHASE-PHASE FAULT: MAXIMUM OPERATION TIMES

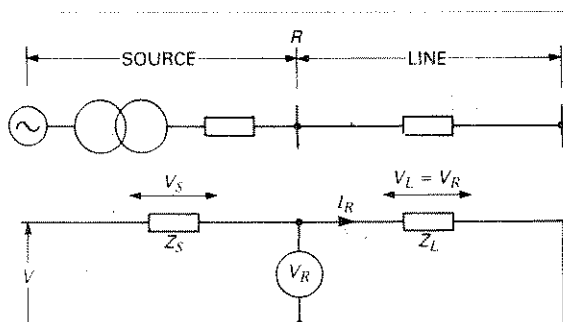
Figure 11.4 Typical isochronic operation time characteristics.

#### 11.4 RELATIONSHIP BETWEEN RELAY VOLTAGE AND $Z_S/Z_L$ RATIO

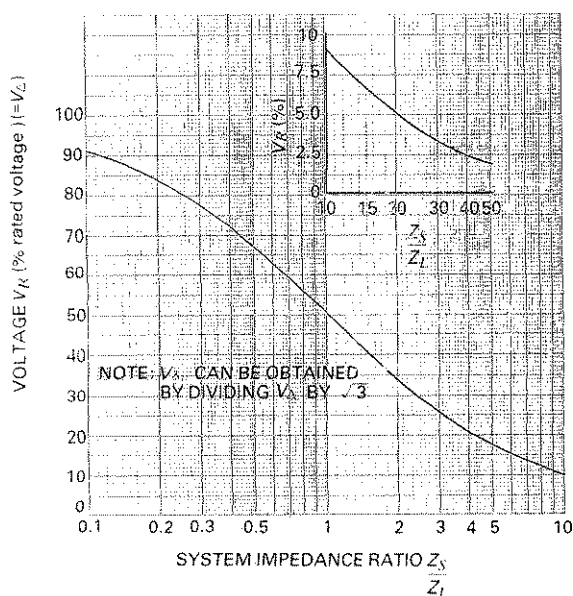
Any fault condition in a three-phase power system may be represented by a single equivalent circuit, as shown in Figure 11.5(a). The voltage  $V$  applied to the impedance loop is the open circuit voltage of the power system. Point  $R$  represents the relay location;  $I_R$  and  $V_R$  are respectively the current and voltage applied to the relay.

The impedances  $Z_S$  and  $Z_L$  are described as source and line

impedances because of their position with respect to the relay location. Source impedance  $Z_S$  is a measure of the fault level at the relaying point, and for faults involving earth is also dependent on the method of system earthing behind the relaying point. Line impedance  $Z_L$  is a measure of the impedance of the protected section. The voltage  $V_R$  applied to the relay is therefore  $I_R Z_L$  for a fault at the reach point; this may be alternatively expressed in terms of source to line impedance ratio  $Z_S/Z_L$  by means of the following expressions:



(a) POWER SYSTEM ARRANGEMENT



(b) VARIATION OF RELAY VOLTAGE WITH SYSTEM SOURCE TO LINE IMPEDANCE RATIO

Figure 11.5 Relationship between source to line ratio and relay voltage.

$$V_R = I_R Z_L$$

where 
$$I_R = \frac{V}{Z_s + Z_L}$$

Therefore 
$$V_R = \frac{Z_L}{Z_s + Z_L} V$$

or 
$$V_R = \frac{1}{(Z_s/Z_L) + 1} V \quad \dots \text{Equation 11.1}$$

The above relationship between  $V_R$  and  $Z_s/Z_L$ , illustrated in Figure 11.5(b), is valid for all types of short circuits provided a few simple rules are observed. These are:

i. For phase faults,  $V$  is the phase to phase voltage and  $Z_s/Z_L$  is the positive sequence source to line impedance ratio.  $V_R$  is the phase to phase relay voltage.

$$V_R = \frac{1}{(Z_{S1}/Z_{L1}) + 1} V_{\Delta} \quad \dots \text{Equation 11.2}$$

ii. For earth faults,  $V$  is the phase to neutral voltage and  $Z_s/Z_L$  is a composite ratio involving the positive and zero sequence impedances.  $V_R$  is the phase to neutral relay voltage.

$$V_R = \frac{1}{(Z_s/Z_L) + 1} V_{\Delta} \quad \dots \text{Equation 11.3}$$

$$\text{or } V_R = \frac{1}{(Z_{S1}/Z_{L1}) \left( \frac{2+p}{2+q} \right) + 1} V_{\Delta} \quad \dots \text{Equation 11.4}$$

where  $Z_s = 2Z_{S1} + Z_{S0} = Z_{S1}(2+p)$   $Z_L = 2Z_{L1} + Z_{L0} = Z_{L1}(2+q)$

## 11.5

### VOLTAGE LIMIT FOR ACCURATE REACH POINT MEASUREMENT

The ability of a distance relay to measure accurately for a reach point fault depends on the minimum voltage at the relay location under this condition being above a declared value. This voltage, which depends on the relay design, can be quoted in terms of an equivalent maximum  $Z_s/Z_L$  or  $SIR$ . For example, the relay with characteristics shown in Figure 11.2 operates within an accuracy tolerance of  $\pm 5\%$  of reach setting down to a voltage of 3.55 volts for a phase to phase fault at the relay zone 1 reach point. This is equivalent to an  $SIR$  of 30, for a relay rated at 110 volts phase to phase.

Relays are designed so that provided the reach point voltage criterion is met, any increased measuring errors for faults closer to the relay will not prevent relay operation. Most modern relays are fitted with sound phase polarization and/or memory characteristics which allow them to operate for close up faults where the relay fault voltage may be small.

## 11.6

### ZONES OF PROTECTION

Correct co-ordination between distance relays on a power system is obtained by controlling the reach settings and tripping times of the various zones of measurement. A conventional distance protection will comprise an instantaneous directional Zone 1 protection and one or more time delayed zones. Typical reach and time settings for a 3 zone distance protection are shown in Figure 11.6.

It is customary to choose a relay reach setting of about 80% of the protected line impedance for the instantaneous Zone 1 protection. The resulting 20% safety margin ensures that there is no risk of the Zone 1 protection over-reaching the protected line, so avoiding loss of discrimination with fast operating protection on the following line section due to errors in the current and voltage transformers, inaccuracies in line impedance data provided for setting purposes and errors of relay setting and measurement. For some applications, where these combined errors allow, the Zone 1 setting can be increased to 85%. However the resulting improvement in operating speed may be insignificant, particularly when carrier aided distance schemes are applied.

The remaining part of the line not covered by Zone 1 is protected by a time delayed directional zone of protection referred to as Zone 2. This may be obtained by extending the reach of the Zone 1 measuring units after a time delay controlled by a fault detector or by the provision of separate Zone 2 measuring units operating after a time delay. The reach setting of the Zone 2 protection is conventionally set to cover the protected line plus 50% of the shortest adjacent line or 120% of the protected line whichever is the greater. The Zone 2 time delay should be set to discriminate with the primary protection of the next line section, including Zone 1 distance protection, if applied, plus the circuit breaker trip time.

Remote back-up protection for all faults on the adjacent line is usually provided by a third zone of protection which is further time delayed to discriminate with Zone 2 protection plus circuit breaker trip time. Zone 3 reach should be set to at least 1.2 times the impedance presented to the relay for a fault at the remote end of the second line section.

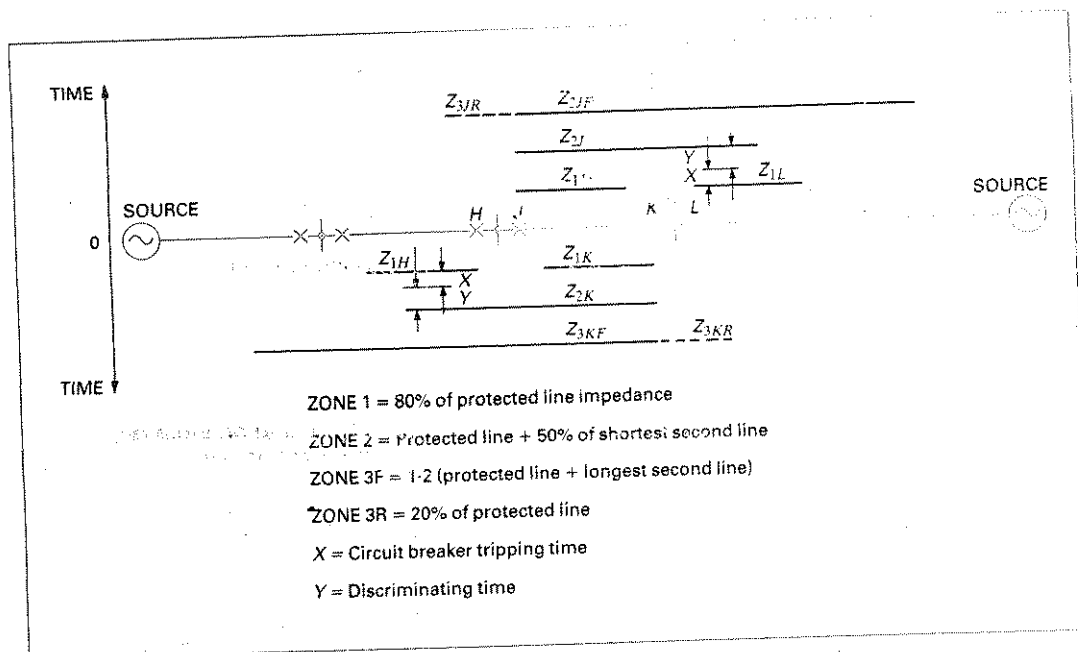


Figure 11.6 Typical time/distance characteristics for three zone distance protection.

On interconnected power systems the effect of fault infeed at the remote busbars will cause the impedance presented to the relay to be much greater than the actual impedance to the fault and this needs to be taken into account when setting Zone 3. In some systems variations in the remote busbar infeed can prevent the application of remote backup Zone 3 protection but on radial distribution systems with single end infeed, no difficulties should arise.

The remote back-up protection is sometimes given a small reverse reach (typically 20% of the protected line section) in addition to its forward reach. This provides time delayed local backup protection for busbar faults and close up three phase faults not cleared by other protections.

In some schemes an instantaneous contact which operates for faults within the offset Zone 3 characteristic is used to provide a 'closing-on-to-fault' or 'line-check' protection to cover the conditions of manually closing on to a line fault. In particular this covers the case of a close up three phase fault due to non-removal of safety earthing clamps from the line following maintenance. For this application, the Zone 3 time delay is bypassed for a short time following manual closing. In other relays the same protection is provided by combinations of current and voltage level detectors and timers. The line check protection is primed whenever the circuit breaker is opened.

## 11.7 SYSTEM CHARTS

To assess the performance of distance relays in relation to the power system parameters and fault conditions on the protected line, charts, as illustrated in Figure 11.7 can be constructed and used in conjunction with the characteristic curves for the distance relay under consideration.

The chart has been constructed for phase fault conditions on a typical 275 kV system and illustrates the variation of source to line impedance ratio  $Z_S/Z_L$  and fault current  $I_F$  with source MVA and the length of protected line. Similar charts can be constructed for earth faults, provided that the power system earthing arrangements are known.

The value of these charts lies in the simplicity with which an assessment of relay suitability can be made, knowing only the switchgear rating and the length of protected line, in addition to the power system operating voltage and the line impedance in ohms per mile or per kilometre.

As a sample of the type of calculation involved in the construction of these charts for phase to phase faults, the case of a relay setting equivalent to 16 km of 275 kV line with a source MVA of 5000 MVA is considered:

Line length 16 km.

Line impedance  $0.31 \angle 84^\circ$  ohm/km.

Total line setting impedance  $Z_{L1} = 4.96$  ohms primary.

Source rating 5000 MVA.

System voltage 275 kV.

Source impedance  $Z_{S1} = \frac{275^2}{5000} = 15.13$  ohms.

$Z_{S1}/Z_{L1} = 3.05$ .

Phase to phase fault current for a fault at the reach point

$$I_F = \frac{275 \times 10^3}{2(Z_{S1} + Z_{L1})} = \frac{275 \times 10^3}{2(15.13 + 4.96)} = 6844 \text{ A.}$$

Voltage transformer ratio = 275,000/110 volts.

$\therefore V_\Delta = 110$ .

The voltage input to the distance relay for a phase to phase fault at the reach point can be calculated from:

$$\begin{aligned} V_R &= \frac{1}{Z_{S1}/Z_{L1} + 1} \cdot V_\Delta \\ &= \frac{1}{3.05 + 1} \cdot V_\Delta = \frac{1}{4.05} \cdot V_\Delta \\ &= 24.7\% \text{ of } V_\Delta \\ &= 27.17 \text{ volts.} \end{aligned}$$

$$\begin{aligned} \text{Alternatively: } V_R &= I_F \times 2 Z_{L1} \times \frac{110}{275,000} \\ &= 6844 \times 2 \times 4.96 \times \frac{110}{275,000} \\ &= 27.16 \text{ volts.} \end{aligned}$$

## 11.8

### RELAY TYPES AND THEIR APPLICATION

Distance relays are classified according to their polar characteristics, the number of inputs they have and the method by which the comparison is made. The common types compare two input quantities in either magnitude or phase to obtain characteristics which are either straight lines or circles when plotted on an  $R/X$  diagram.

Relay movements and circuits in which two independent quantities are compared are essentially either amplitude or phase comparators. The balanced-beam relay is an amplitude comparator, because the resultant torque is entirely dependent on the magnitude of the input quantities. The induction cup, however, is a phase comparator, because the resultant torque is only in the operating direction when

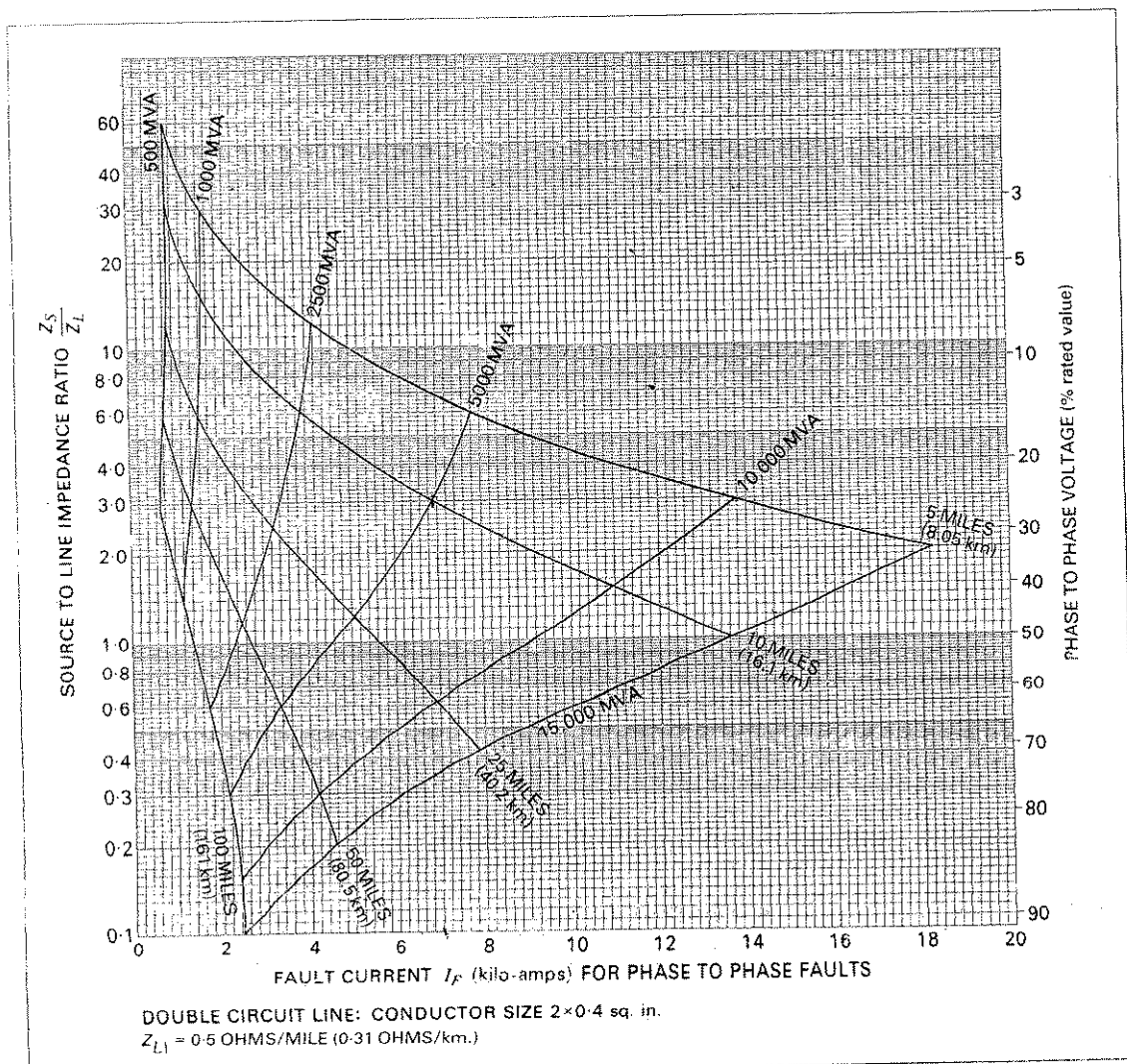


Figure 11.7 275 kV power system chart.

the angle between the input quantities is within the limits  $\pm 90^\circ$ .

Any type of characteristic obtainable with one comparator is also obtainable with the other, although the combination of quantities compared is different in each case. For example, comparing  $V$  and  $I$  in an amplitude comparator results in a circle characteristic centred at the origin of the  $R/X$  diagram. If, however,  $V$  and  $I$  are compared in a phase comparator, the characteristic is a straight line passing through the origin. One the other hand, if the sum and difference of  $V$  and  $I$  are applied to the phase comparator the original circle characteristic is obtained.

Modern static distance relays generally use phase comparators either of the block average or sequence type. Block average comparators are used in the YTG and PYTS distance relays while sequence comparators are used in the 'Micromho' and 'Quadramho' distance relays. Details of the operation of these comparators may be found in Chapter 7, Section 7.2.5.

### 11.9

#### PLAIN IMPEDANCE RELAY

The impedance relay takes no account of the phase angle between the current and the voltage applied to it; for this reason its impedance characteristic when plotted on an  $R/X$  diagram is a circle with its centre at the origin of the co-ordinates and of radius equal to its setting in ohms. The relay operates for all impedance values less than its setting, that is, for all points within the circle. The relay, shown in Figure 11.8, is therefore non-directional, and in this form would operate for all faults along the vector  $GL$  and also for all faults behind the busbars up to an impedance  $GM$ . It is

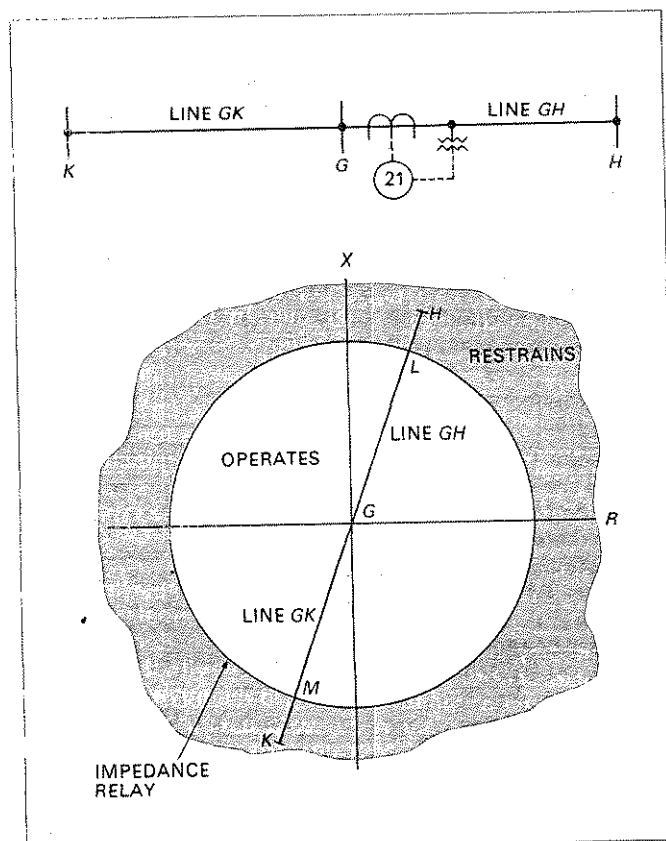


Figure 11.8 Plain impedance relay characteristic.

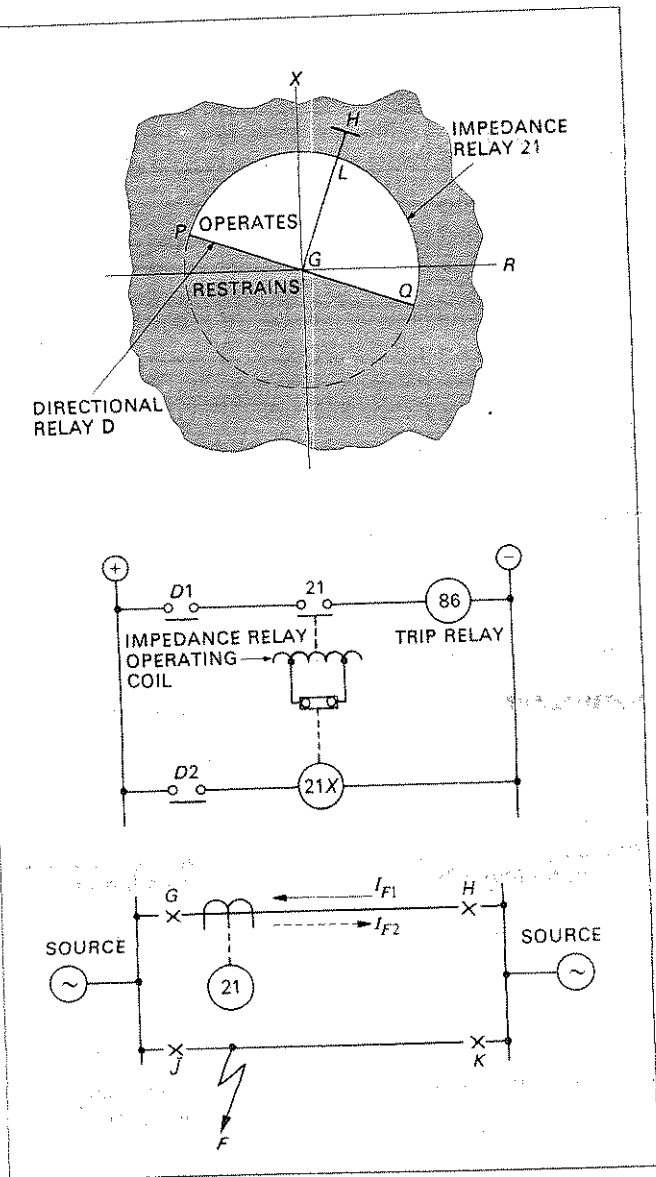


Figure 11.9 Combined directional and impedance relays.

to be noted that  $G$  is the relaying point and  $RGH$  is the angle by which the fault current lags the relay voltage for a fault on the line  $GH$  and  $RGK$  is the equivalent leading angle for a fault on line  $GK$ . Vector  $GH$  represents the impedance in front of the relay between the relaying point  $G$  and the end of line  $GH$ . Vector  $GK$  represents the impedance of line  $GK$  behind the relaying point. The reach of instantaneous Zone 1 protection set to cover 80% to 85% of the protected line is represented by  $GL$ .

The plain impedance relay has three important disadvantages:

- It is non-directional; it will see faults both in front of and behind the relaying point, and therefore requires a directional element to give it correct discrimination.
- It is affected by arc resistance.
- It is highly sensitive to power swings, because of the large area covered by the impedance circle.

To make the relay non-responsive to busbar and feeder faults behind it, directional control is essential. This can be obtained by the addition of a separate directional relay with two pairs of contacts, one pair in series with the impedance relay contact in the trip circuit and the other connected to energize an auxiliary relay, whose contacts in the de-energized condition short-circuit the current coil of the impedance relay and are opened under fault conditions if the power flow is from the busbars into the protected line. This directional control is essential in order to avoid con-

tact race between the impedance relay and the directional unit in interconnected or double circuit lines.

The impedance characteristic of the directional relay is a straight line on the  $R/X$  diagram, and the combined characteristic of the directional and impedance relays is the semi-circle  $GPLQ$  shown in Figure 11.9. It will be noted that the combined relay characteristic measures impedance in the forward direction only; it is prevented from measuring in the backward direction by the directional unit. Faults along the line  $GH$  cause operation of the directional unit, which in turn removes the short circuit from the impedance relay current coil, allowing it to measure the fault loop impedance and to operate the trip relay if it is within its reach setting  $GL$ .

If a fault occurs at  $F$  close to  $J$  on the parallel line  $JK$ , the directional unit  $D$  at  $G$  will restrain due to current  $I_{F1}$ . At the same time, the impedance unit is prevented from operating by contact  $D2$  and auxiliary unit  $21X$ . If this control is not provided, contact 21 could close prior to circuit breaker  $J$  opening. Reversal of current through the relay from  $I_{F1}$  to  $I_{F2}$  when  $J$  opens could then result in incorrect tripping of the healthy line if the directional unit  $D$  operates before the impedance unit 21 resets. This is avoided by preventing the impedance unit from operating unless fault current is in the required direction, that is, from  $G$  to  $L$ .

### 11.10

#### MHO RELAY - SELF-POLARIZED MHO

The mho relay, generally known as such because its characteristic is a straight line on an admittance diagram, combines by the addition of a polarizing signal the characteristics of both the impedance and directional relays.

The characteristic of this relay when plotted on an  $R/X$  diagram is a circle whose circumference passes through the origin, as illustrated in Figure 11.10(b) showing that the relay is inherently directional and will operate only for faults in the forward direction on line  $GL$ .

The characteristic is adjusted by setting  $Z_n$ , the impedance reach along the diameter and  $\phi$ , the angle of displacement of the diameter from the  $R$  axis. Angle  $\phi$  is known as the relay characteristic angle ( $RCA$ ). The relay operates for values of fault impedance  $Z_f$  within its characteristic.

The self-polarized mho characteristic can be obtained using a phase comparator circuit which compares input signals  $S_2$  and  $S_1$  and operates whenever  $S_2$  lags  $S_1$  by between  $90^\circ$  and  $270^\circ$ , as shown in the voltage diagram of Figure 11.10(a).

The two input signals are:

$$\left. \begin{aligned} S_2 &= V - IZ_n \\ S_1 &= V \end{aligned} \right\} \quad \dots \text{Equation 11.5}$$

where  $V$  = fault voltage from VT secondary winding

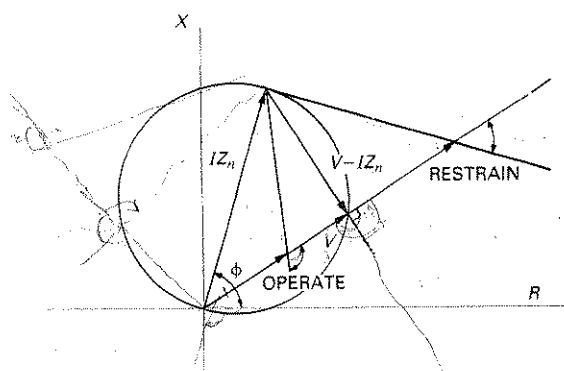
$I$  = fault current from CT secondary winding

$Z_n$  = impedance setting of distance relay in secondary ohms.

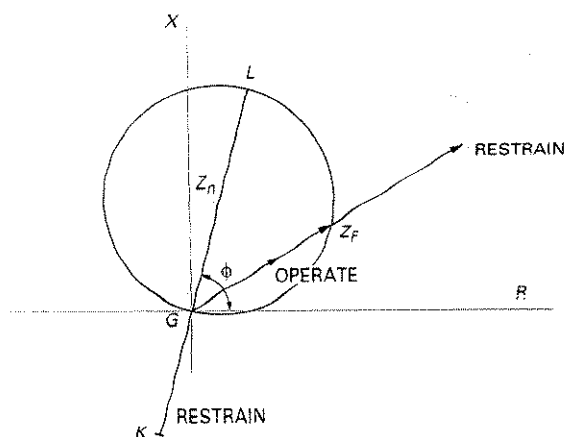
Alternatively the mho characteristic can be generated using input signals  $S_2 = V - IZ_n$  and  $S_1 = -V$  or  $S_2 = IZ_n - V$  and  $S_1 = V$  but in these cases the phase comparator would be set for operation whenever  $S_2$  is within  $\pm 90^\circ$  of  $S_1$ .

The characteristic of Figure 11.10(a) can be converted to the impedance plane of Figure 11.10(b) by dividing each voltage by  $I$ .

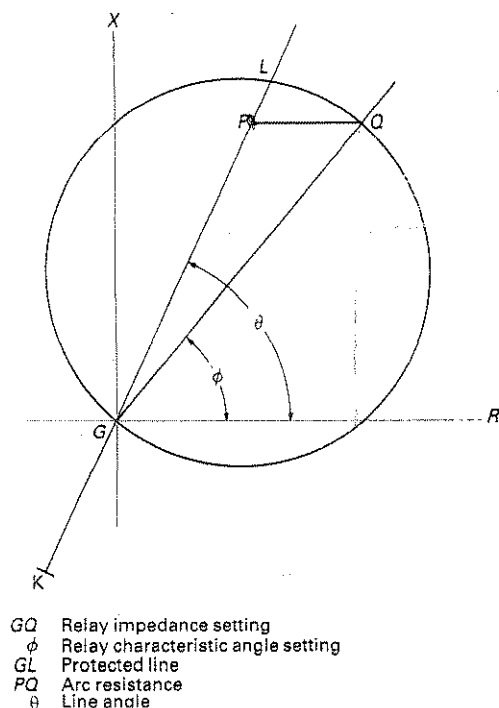
It will be noted that the impedance reach varies with fault angle. As the line to be protected is made up of resistance and inductance, its fault angle will be dependent upon the relative values of  $R$  and  $X$ . Under an arcing fault condition the value of the resistive component will increase and change this fault angle, so that a relay having a characteristic angle equivalent to the line angle will, under arcing conditions, under-reach.



(a) PHASE COMPARATOR INPUTS.



(b) MHO IMPEDANCE CHARACTERISTIC



- GQ Relay impedance setting
- $\phi$  Relay characteristic angle setting
- GL Protected line
- PQ Arc resistance
- $\theta$  Line angle

(c) INCREASED ARC RESISTANCE COVERAGE.

Figure 11.10 Mho relay characteristic.

It is usual, therefore, to apply a relay with its characteristic angle ( $RCA$ ) set less than the line angle, so that it is possible to accept a small amount of arc resistance without causing under-reach. However, when setting the relay, the difference between the line angle  $\theta$  and the relay characteristic angle  $\phi$  must be known. The resulting characteristic is shown in Figure 11.10(c) where  $GL$  corresponds to the length of the line to be protected. If the relay characteristic angle  $\phi$  were set equal to  $\theta$  then  $GL$  would equal the relay setting. However, with  $\phi$  set less than  $\theta$ , the actual amount of line protected,  $GL$ , would be equal to the relay setting value  $GQ$  multiplied by cosine  $(\theta - \phi)$ . Therefore the required relay setting  $GQ$  is given by:

$$GQ = \frac{GL}{\cos(\theta - \phi)}$$

It should be appreciated that the arc resistance bears no relation to the neutral earth resistance in regard to the relay setting value. The latter resistance is in the source behind the relay and only modifies the source angle and source to line impedance ratio for earth faults. It would therefore be taken into account only when assessing relay performance in terms of system impedance ratio.

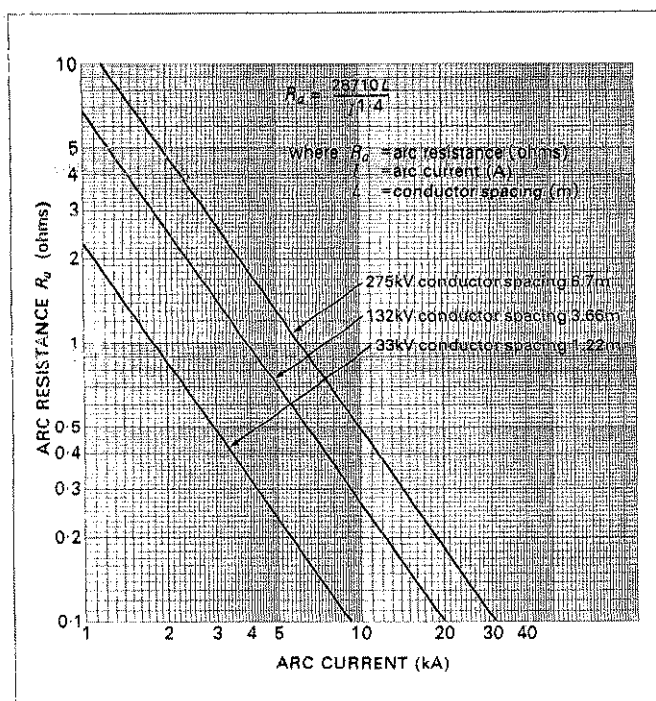


Figure 11.11 Typical arc resistance/current curves for high voltage systems.

The approximate value of arc resistance can be assessed from Figure 11.11 which makes use of the empirical formula derived by A.R. van C. Warrington:

$$R_a = \frac{28,710}{I^{1.4}} L \quad \dots \text{Equation 11.6}$$

Where  $R_a$  = arc resistance (ohms).

$L$  = length of arc (metres).

$I$  = current in the arc (A).

The effect of arc resistance is most significant on short lines and with fault currents below 2000 A. This latter condition applies during light load periods, when the connected plant is reduced to a minimum.

On long lines carried on steel towers with overhead earth wires the effect of arc resistance can usually be neglected, but where the transmission line is carried on wooden poles without earth wires, the earth fault resistance can have serious consequences for the application of self-polarized mho relays used for earth fault measurement. This is

because it reduces the effective Zone 1 reach to such an extent that the majority of faults are detected in Zone 2 time. This problem can usually be overcome by using reactance, quadrilateral or fully cross-polarized mho relays for the detection of earth faults.

### 11.11 REACTANCE RELAY

For all practical purposes, the setting of the reactance relay does not vary in the presence of arc resistance, because it is designed to measure only the reactive component of the line. It may be seen from the relay characteristics shown in Figure 11.12(a) that, in theory, any increase in the resistive component of the fault impedance will have no effect upon the relay reach, as the relay will continue to measure the same value of reactance  $X$ .

However, when the fault resistance is of such a high value that load and fault current magnitudes are of the same order, the reach of the relay is modified by the value of the load and its power factor and may either over-reach or under-reach.

This is explained by reference to Figure 11.12(b) which shows a fault with high resistance  $R_F$  fed from both ends of a transmission line carrying load current. For simplicity the power system has been reduced to an equivalent two-machine system. In the example shown source voltage  $E_G$  is considered as leading  $E_H$  due to pre-fault load transfer.

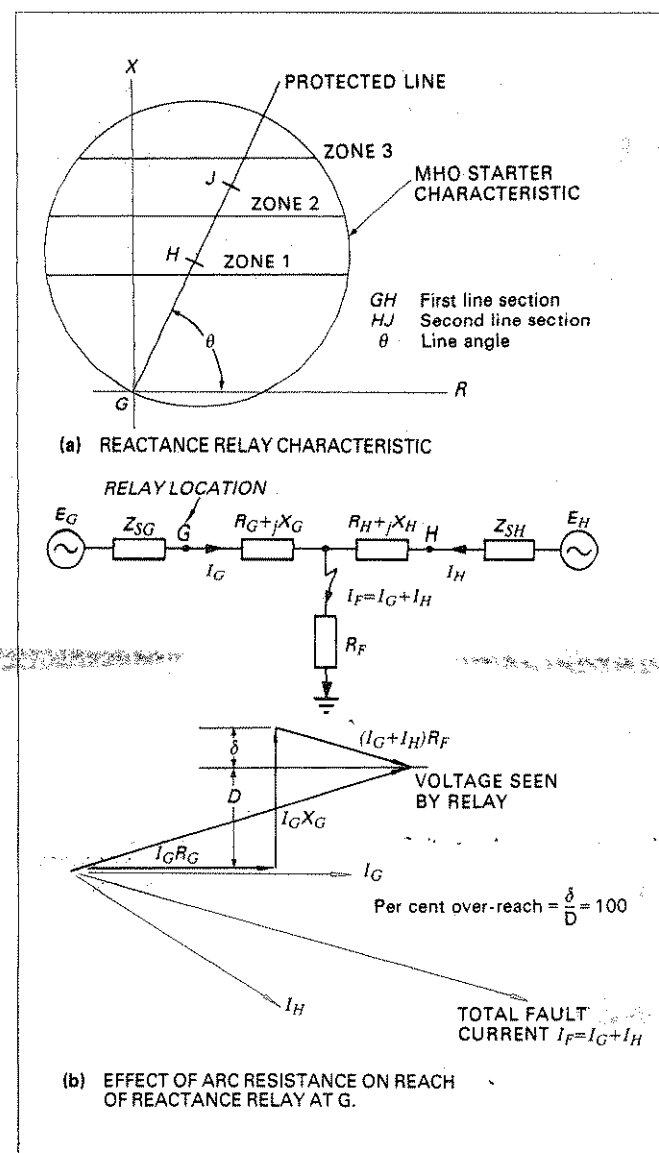


Figure 11.12 Characteristic and performance of reactance relay with double infeed and different phase angles.

Under fault conditions the fault current  $I_F$  is the vector sum of the two currents  $I_G$  and  $I_H$  fed from each end of the system.

Due to the fact that the fault current  $I_F$  is not in phase with the currents  $I_G$  and  $I_H$  measured by relays at  $G$  and  $H$ , the fault resistance  $R_F$  will appear to these relays as a complex impedance. Figure 11.12(b) shows the vector diagram for a reactance relay at  $G$  on the line having leading source angle. From this it can be seen that the reactance  $D$  presented to the relay is less than the actual line reactance to the fault  $X_G$ , and that, as a result, the relay over-reaches. Similarly a relay at  $H$  on the line having a lagging source angle would under-reach.

### 11.12 QUADRILATERAL RELAY

The reactance relay has been generally superseded by relays with quadrilateral characteristics which combine the advantages of the reactance relay with directional and resistive reach control characteristics. Quadrilateral characteristics are applied for earth fault protection on lines of short to medium length with strong sources of power infeed when a high degree of tolerance to fault resistance is required.

Some relays with quadrilateral earth fault characteristics such as those of 'Quadramho' shown in Figure 11.13 have circuits which overcome the basic problem of the reactance relay over-reaching or under-reaching due to pre-fault load. In these relays the reactance characteristic of Zone 1 is arranged to swing about the Zone 1 reach point in such a way as to compensate for the pre-fault load flow. This allows correct Zone 1 measurement even in the presence of pre-fault load flow.

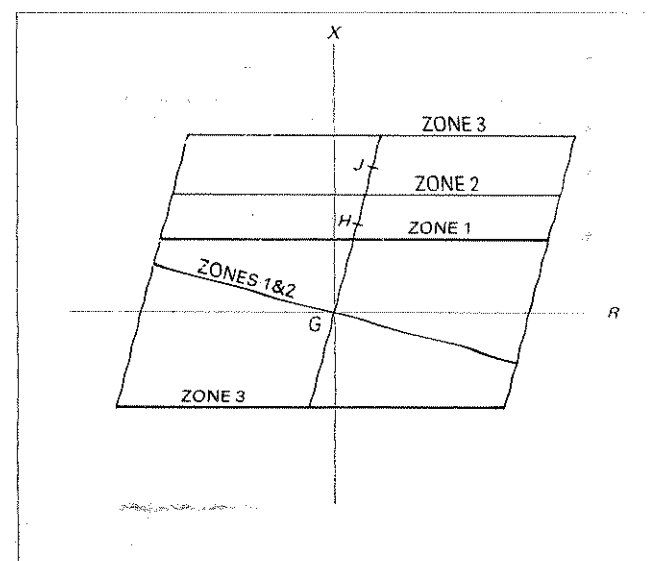


Figure 11.13 Quadrilateral earth fault characteristics of distance relay.

### 11.13 OFFSET MHO OR LENTICULAR RELAY

Under close up fault conditions, when the relay voltage falls to zero or near-zero, a self-polarized mho or directional relay may fail to operate when it is required to do so. Alternative methods of covering this condition include the use of offset characteristics such as offset mho and lenticular characteristics and cross-polarized and memory polarized characteristics.

If current bias is employed, the mho characteristic is shifted to embrace the origin, and the measuring element operates for close-up faults both in the forward and the reverse direction of the relay. The offset mho relay has three main applications.



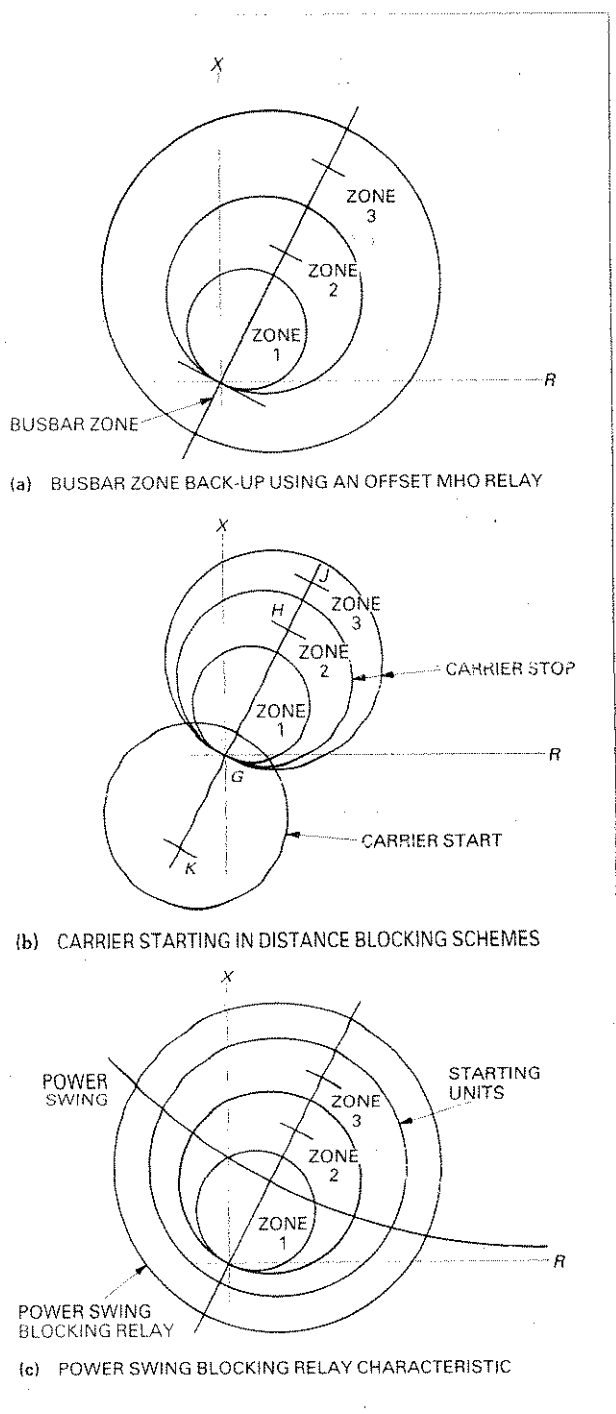


Figure 11.14 Typical applications for the offset mho relay.

**a. Third zone and busbar back-up zone**

In this application it is used in conjunction with mho measuring units as a fault detector and/or Zone 3 measuring unit. So, with the reverse reach arranged to extend into the busbar zone, as shown in Figure 11.14(a), it will provide back-up protection for busbar faults. This facility can also be provided on quadrilateral characteristics. A further feature of the Zone 3 application is for the closing-on-to-fault protection as described at the end of Section 11.6.

**b. Carrier starting unit in distance schemes with carrier blocking.**

If the offset mho unit is used for starting carrier signalling, it is arranged as shown in Figure 11.14(b). Carrier is transmitted if the fault is external to the protected line but inside the reach of the offset mho relay, in order to prevent accelerated tripping of the second or third zone relay at the remote station. Transmission is prevented for internal faults by a contact of the local mho measuring units, which

allows high speed fault clearance by the local and remote end circuit breakers.

**c. Power swing blocking.**

In this application the relay is arranged to block operation of the distance scheme measuring units during power swing conditions. A typical arrangement is shown in Figure 11.14(c). The locus of the impedance vector 'seen' during a power swing condition cuts the characteristics of both the blocking units and the measuring units. If the measuring units operate within a certain time after the operation of the blocking relay, tripping is allowed. If, on the other hand, after the predetermined time delay the measuring units have not operated, the tripping circuit is isolated so that if the measuring relays do eventually operate, tripping will not take place. Thus, under fault conditions, when the power swing blocking relay and the distance measuring relays will operate practically simultaneously, tripping is allowed. But under power swing conditions, should the distance measuring relays operate, they would do so after the power swing blocking relay, and thereby tripping is effectively prevented. This eliminates the danger of cascade tripping of transmission lines.

Where it is desired to set the Zone 3 offset mho relay shown in Figure 11.14(a) to a large reach to provide remote back-up protection for faults on the adjacent feeder, there is a danger that the relay may operate under maximum load transfer conditions. To avoid this the Zone 3 characteristic in the 'Micromho' relay can be of the lenticular type in which the aspect ratio of the lens ( $\frac{a}{b}$ ) is adjustable enabling it to be set to provide the maximum fault resistance coverage consistent with non-operation under maximum load transfer conditions.

Figure 11.15 shows how the lenticular characteristic can tolerate much higher degrees of line loading than offset mho and impedance characteristics. Reduction of load impedance from  $Z_{D3}$  to  $Z_{D1}$  will correspond to an equivalent increase in load current.

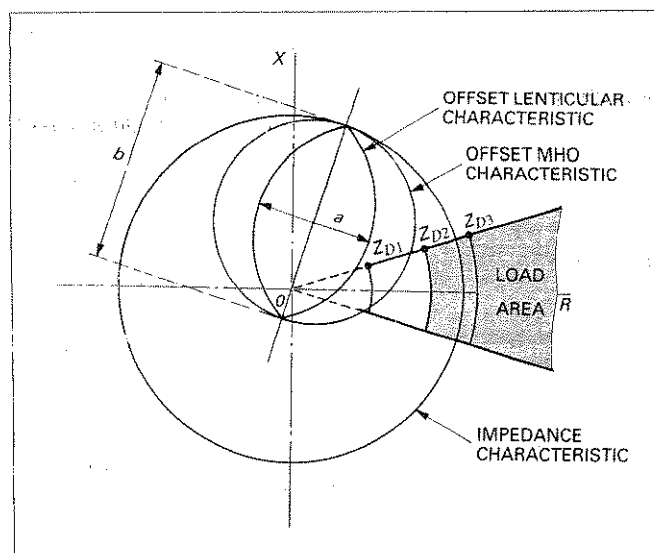


Figure 11.15 Minimum load impedance permitted with lenticular, offset mho and impedance relays.

**11.14**

**CROSS-POLARIZATION AND MEMORY**

Section 11.13 showed how the offset mho is inherently able to operate for close-up zero-voltage faults, unlike the self-polarized mho. Another way of ensuring correct response to zero-voltage faults is to add a percentage of voltage from a phase not associated with the fault, to the polarizing voltage. This technique is called cross-polarizing, and has the advantage of preserving and indeed enhancing the directional properties of the mho characteristic.



Cross-polarizing is ineffective for close-up three-phase faults where all phases of voltage collapse. This is not necessarily a serious disadvantage since the probability of complete voltage collapse after the line has been energized for some time (as distinct from a solid bolted-on fault) is rather remote, because arc resistance associated with the fault will always produce at least 0.5 V at the relay terminals.

Even a relay with a self-polarized characteristic will generally operate correctly at 0.5 V, although transient errors in the voltage signal caused by capacitor-type voltage transformers may sometimes provoke reverse maloperation or slow forward operation in such a relay.

To give improved performance for three-phase close-up faults a voltage reference circuit known as a memory circuit is commonly used. On early designs of distance relay, analogue oscillatory circuits tuned to the power system frequency were used to 'remember' the pre-fault voltage. Such circuits could cause problems if the power frequency deviated from its nominal value, because under fault conditions the memory signal would accumulate a phase error after a few cycles, with attendant risk of incorrect relay response.

The latest designs of distance relay, 'Micromho' and 'Quadramho', contain digital synchronous polarizing circuits which overcome the problems of early memory circuits.

Synchronous polarizing circuits memorize several cycles of pre-fault voltage information with the correct frequency and phase. When the line is first energized, a few cycles are needed for the synchronous polarizing to lock on to the frequency and phase of the mains supply, so the offset mho Zone 3 units are used for instantaneous clearance of faults during this time, as explained in Section 11.6.

Cross-polarizing and memory circuits permit fast operation for close-up faults in the forward direction of the relay, and ensure stability for close-up faults in the reverse direction. The circuit designs in 'Micromho' and 'Quadramho' guarantee this performance even in the presence of capacitor voltage transformer transient errors. Cross-polarizing and memory techniques also increase coverage of arc resistance, as explained in the next Section.

### 11.15

#### FULLY CROSS-POLARIZED MHO RELAY

As described in Section 11.10, a disadvantage of the self-polarized mho characteristic when applied to overhead circuits especially with large angles is that it has limited coverage of arc or fault resistance.

The problem is aggravated in the case of short lines, since the required Zone 1 ohmic setting is low and the amount of the  $R$  axis covered by the mho circle is small in relation to the expected values of arc resistance.

One practical solution to this problem of large arc resistances and higher resistance faults is to use a fully cross-polarized mho relay, which will open out its mho circular characteristic, along the  $R$  axis, as shown in Figure 11.16, for all types of unbalanced faults. The fully cross-polarized mho characteristic can be obtained by the use of a phase comparator circuit, which compares input signals  $S_2$  and  $S_1$  and operates whenever  $S_2$  lags  $S_1$  by between  $90^\circ$  and  $270^\circ$ .

The two input signals for this comparator are:

$$S_2 = V - IZ_n$$

$$S_1 = V_{pol}$$

where  $V$  = fault voltage from voltage transformer secondary winding.

$V_{pol}$  = polarizing voltage derived from the voltage transformer secondary winding of the healthy phase or phases. The direction of  $V_{pol}$  is chosen so that under non-fault conditions it is in phase with  $V$ .

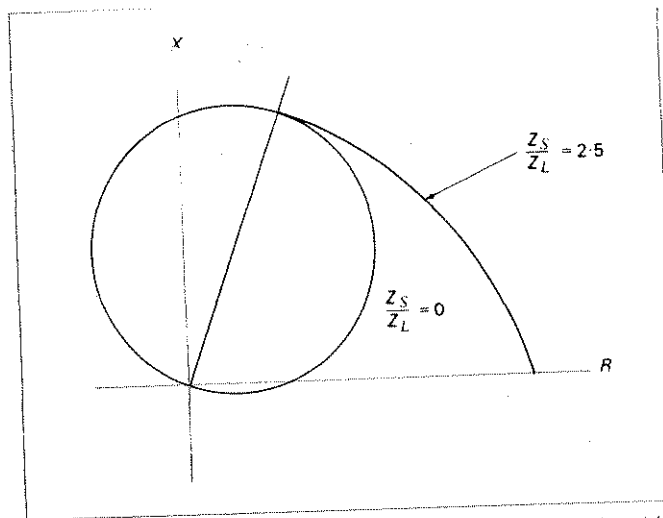


Figure 11.16 Fully cross-polarized mho relay characteristic with variations of  $Z_s/Z_L$  ratio.

$I$  = fault current from current transformer secondary winding.

$Z_n$  = impedance setting of distance relay in secondary ohms.

As an illustration of the opening of the mho circle during unbalanced faults, the relay characteristic can be analyzed as follows:

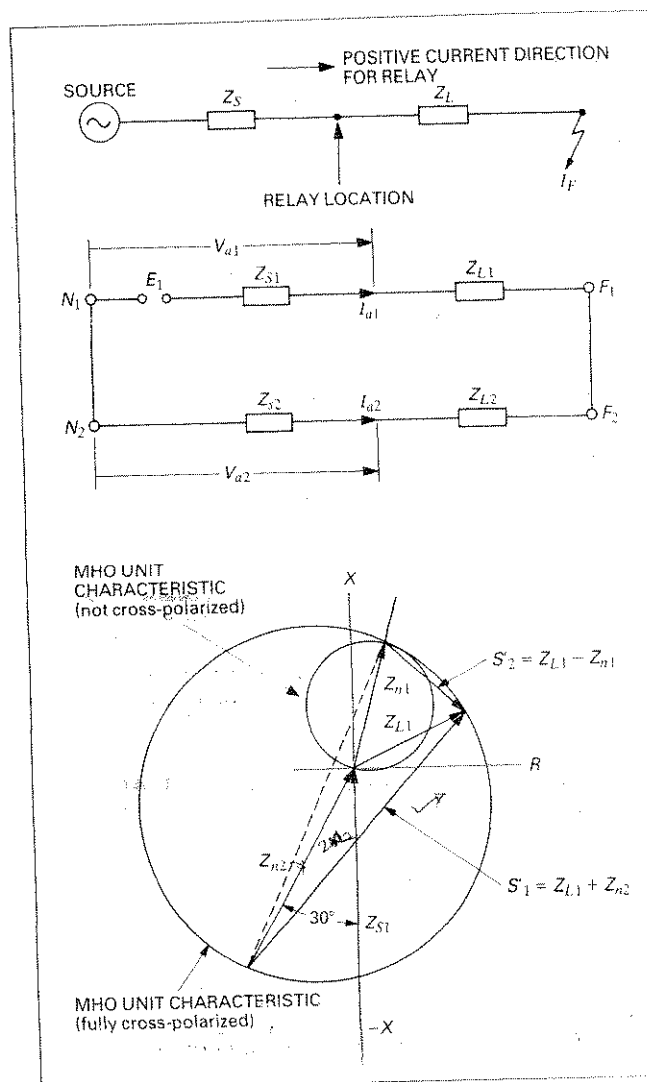


Figure 11.17 Fully cross-polarized mho relay characteristic for a phase to phase fault in the forward direction.

### Analysis for a phase to phase fault.

Consider the case of a B-C fault, when the relay is cross-polarized with A-B voltage. The sequence network for a phase fault is shown in Figure 11.17.

$$\begin{aligned}
 I_{a1} &= -I_{a2} = \frac{E_1}{2(Z_{S1} + Z_{L1})} \\
 V_{a1} &= E_1 - I_{a1}Z_{S1} \\
 &= E_1 - \frac{E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 V_{a2} &= 0 - I_{a2}Z_{S2} \\
 &= \frac{E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 V_a &= V_{a1} + V_{a2} \\
 &= E_1 - \frac{E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} + \frac{E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= E_1 \\
 V_b &= a^2 V_{a1} + a V_{a2} \\
 &= a^2 E_1 - \frac{a^2 E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} + \frac{a E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{2a^2 E_1 (Z_{S1} + Z_{L1})}{2(Z_{S1} + Z_{L1})} - \frac{a^2 E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} + \frac{a E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{2a^2 E_1 Z_{L1}}{2(Z_{S1} + Z_{L1})} + \frac{2a^2 E_1 Z_{S1} - a^2 E_1 Z_{S1} + a E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{2a^2 E_1 Z_{L1}}{2(Z_{S1} + Z_{L1})} + \frac{(a^2 + a) E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{E_1}{2(Z_{S1} + Z_{L1})} (2a^2 Z_{L1} - Z_{S1}) \\
 V_c &= a V_{a1} + a^2 V_{a2} \\
 &= \frac{2a E_1 (Z_{S1} + Z_{L1})}{2(Z_{S1} + Z_{L1})} - \frac{a E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} + \frac{a^2 E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{2a E_1 Z_{L1}}{2(Z_{S1} + Z_{L1})} + \frac{2a E_1 Z_{S1} - a E_1 Z_{S1} + a^2 E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{2a E_1 Z_{L1}}{2(Z_{S1} + Z_{L1})} - \frac{E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{E_1}{2(Z_{S1} + Z_{L1})} (2a Z_{L1} - Z_{S1}) \\
 V_{ba} &= \frac{E_1}{2(Z_{S1} + Z_{L1})} (2a^2 Z_{L1} - Z_{S1}) - E_1 \\
 &= \frac{2a^2 E_1 Z_{L1} - E_1 Z_{S1} - 2E_1 Z_{S1} - 2E_1 Z_{L1}}{2(Z_{S1} + Z_{L1})} \\
 &= \frac{2E_1 Z_{L1} (a^2 - 1) - 3E_1 Z_{S1}}{2(Z_{S1} + Z_{L1})} \\
 &= E_1 \frac{(a^2 - 1) Z_{L1} - 1.5 Z_{S1}}{(Z_{S1} + Z_{L1})} \\
 V_{bc} &= \frac{E_1}{2(Z_{S1} + Z_{L1})} (2a^2 Z_{L1} - Z_{S1}) \\
 &\quad - \frac{E_1}{2(Z_{S1} + Z_{L1})} (2a Z_{L1} - Z_{S1}) \\
 &= \frac{2E_1 Z_{L1} (a^2 - a)}{2(Z_{S1} + Z_{L1})}
 \end{aligned}$$

$$= \frac{E_1 (a^2 - a) Z_{L1}}{(Z_{S1} + Z_{L1})}$$

$$I_a = I_{a1} + I_{a2}$$

$$= 0$$

$$I_b = a^2 I_{a1} + a I_{a2}$$

$$= \frac{a^2 E_1}{2(Z_{S1} + Z_{L1})} - \frac{a E_1}{2(Z_{S1} + Z_{L1})}$$

$$= \frac{(a^2 - a) E_1}{2(Z_{S1} + Z_{L1})}$$

$$I_c = a I_{a1} + a^2 I_{a2}$$

$$= \frac{a E_1}{2(Z_{S1} + Z_{L1})} - \frac{a^2 E_1}{2(Z_{S1} + Z_{L1})}$$

$$= \frac{(a - a^2) E_1}{2(Z_{S1} + Z_{L1})}$$

$$I_b - I_c = \frac{(a^2 - a) E_1}{2(Z_{S1} + Z_{L1})} - \frac{(a - a^2) E_1}{2(Z_{S1} + Z_{L1})}$$

$$= \frac{(a^2 - a) E_1}{(Z_{S1} + Z_{L1})}$$

Now the two input signals to the phase comparator are:

$$S_2 = V - I Z_n$$

$$S_1 = V_{pol}$$

Where  $V = V_{bc}$  for a B-C fault

$$= \frac{(a^2 - a) E_1 Z_{L1}}{(Z_{S1} + Z_{L1})}$$

$$I = I_{bc} \text{ for a B-C fault}$$

$$= \frac{(a^2 - a) E_1}{(Z_{S1} + Z_{L1})}$$

$Z_n = \bar{Z}_{n1}$  = ohmic reach setting of fully cross-polarized mho relay

$$V_{pol} = K_1 V_{ba}$$

and, for 100% cross-polarizing  $K_1 = 1/60^\circ$

$$V_{ab} = E_1 \left\{ \frac{(1 - a^2) Z_{L1} + 1.5 Z_{S1}}{(Z_{S1} + Z_{L1})} \right\}$$

$$\therefore S_2 = \frac{(a^2 - a) E_1 Z_{L1}}{(Z_{S1} + Z_{L1})} - \frac{(a^2 - a) E_1 Z_{n1}}{(Z_{S1} + Z_{L1})}$$

$$= \frac{(a^2 - a) E_1}{(Z_{S1} + Z_{L1})} (Z_{L1} - Z_{n1})$$

$$S_1 = 1/60^\circ E_1 \left\{ \frac{(a^2 - 1) Z_{L1} - 1.5 Z_{S1}}{(Z_{S1} + Z_{L1})} \right\}$$

$$= -a^2 E_1 \left\{ \frac{(a^2 - 1) Z_{L1} - 1.5 Z_{S1}}{(Z_{S1} + Z_{L1})} \right\}$$

$$= E_1 \left\{ \frac{(a^2 - a) Z_{L1} + 1.5 a^2 Z_{S1}}{(Z_{S1} + Z_{L1})} \right\}$$

$$= \frac{E_1}{(Z_{S1} + Z_{L1})} \left\{ (a^2 - a) Z_{L1} + 1.5 a^2 \frac{(1 - a^2)}{(1 - a^2)} Z_{S1} \right\}$$

$$= \frac{E_1}{(Z_{S1} + Z_{L1})} \left\{ (a^2 - a) Z_{L1} + 1.5 \frac{(a^2 - a)}{(1 - a^2)} Z_{S1} \right\}$$

$$= \frac{E_1}{(Z_{S1} + Z_{L1})} (a^2 - a) \left\{ Z_L + \frac{\sqrt{3}}{2} Z_{S1} \angle -30^\circ \right\}$$

Multiplying both signals  $S_2$  and  $S_1$  by the vector  $(Z_{S1} + Z_{L1})/E_1(a^2 - a)$  will not affect the relative phase relation between them:

$$S'_2 = Z_{L1} - Z_{n1}$$

$$S'_1 = Z_{L1} + \frac{\sqrt{3}}{2} Z_{S1} \angle -30^\circ$$

$$= Z_{L1} + Z_{n2}$$

$$\text{where } Z_{n2} = \frac{\sqrt{3}}{2} Z_{S1} \angle -30^\circ$$

It must be emphasized that the extension of the fully cross-polarized characteristic into the negative reactance quadrants of Figure 11.17 does not in this instance imply operation for reverse faults. The foregoing analysis only applies for forward faults, from which it is apparent that close-up faults in the forward direction of the relay are well within the circular characteristic. The characteristic can be seen in Figure 11.18 to change to an offset circle clear of the origin for reverse faults. As the fault current for a reverse fault is negative when seen by a forward looking relay, the two signals for comparison are:

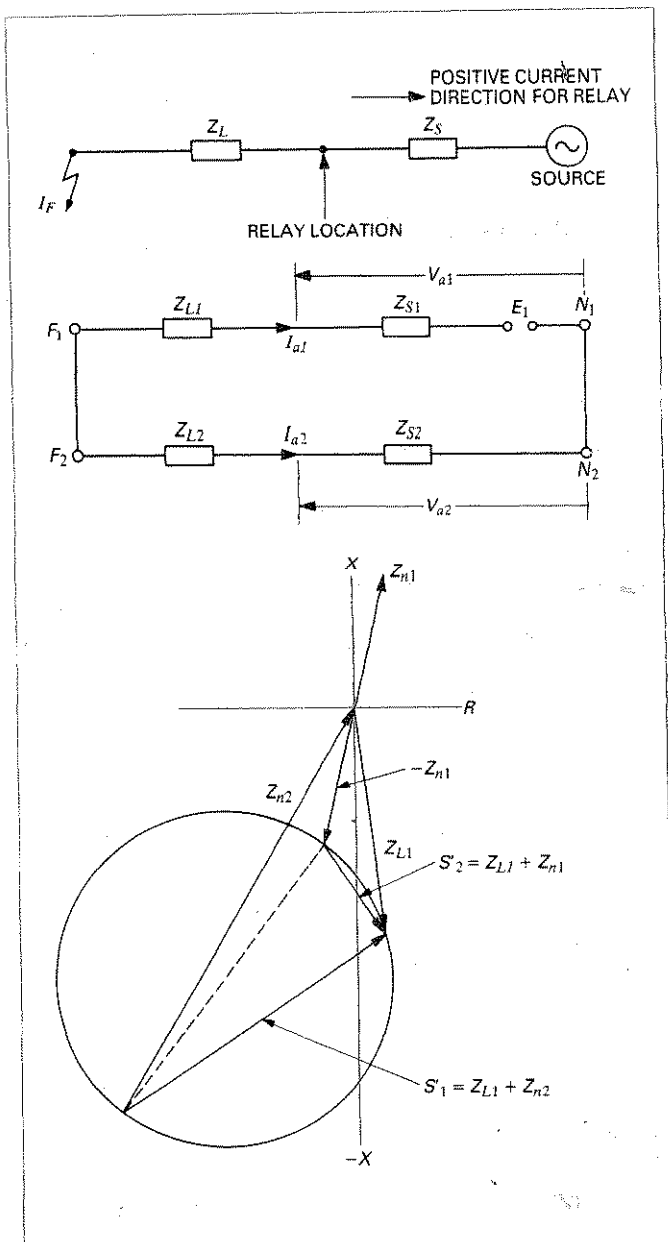


Figure 11.18 Fully cross-polarized mho relay characteristic for a phase to phase fault in the reverse direction.

$$S'_2 = Z_{L1} + Z_{n1}$$

$$S'_1 = Z_{L1} + Z_{n2}$$

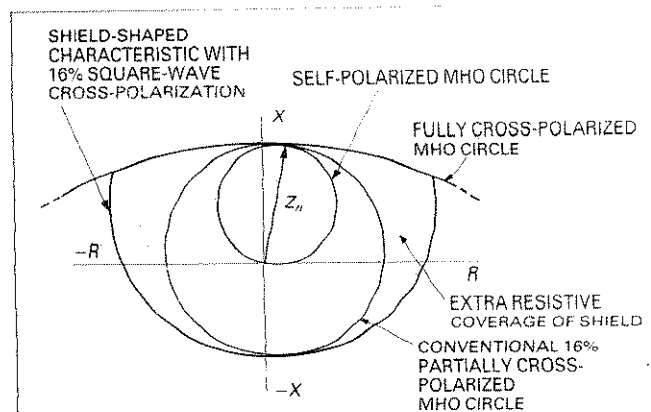
It can be seen that the relay will not operate for any reverse fault having inductive fault impedance. For the phase to phase fault considered, the only possibility of operation would be for a capacitive fault impedance behind the relay falling within the circular characteristic. Therefore the relay is stable for close-up reverse faults and in most practical applications will not operate for any reverse fault.

## 11.16

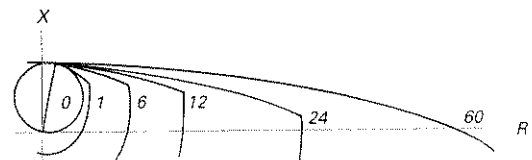
### PARTIALLY CROSS-POLARIZED MHO RELAY

A penalty of full cross-polarization of the mho characteristic is an increased tendency for comparators connected to healthy phases to operate under heavy fault conditions on another phase. This is of no consequence in a switched distance relay, where a single comparator is connected to the correct fault loop impedance by starting units before measurement begins. However, in a full scheme distance relay where independent comparators are permanently connected to each of the three earth fault and three phase fault loops the maloperation of healthy phases is undesirable especially when single-pole tripping is required for single-phase faults.

The partially cross-polarized mho is frequently used as a compromise between the excellent phase selection of the self-polarized mho and the superior arc resistance coverage and directional response of the fully cross-polarized mho. The polarizing signal  $S_1$  of the partially cross-polarized mho comparator consists of a mixture of the self-voltage for the particular phase of the comparator, plus a proportion of the cross-polarizing voltage. The analysis is similar to that given in Section 11.15 except that



(a) COMPARISON OF POLARIZED CHARACTERISTICS DRAWN FOR SIR = 6



(b) RESISTIVE EXPANSION OF SHAPED PARTIALLY CROSS-POLARIZED MHO WITH INCREASING VALUES OF SIR.

Figure 11.19 Partially cross-polarized characteristic with 'shield' shape.

impedance  $Z_{n2}$  shown in Figure 11.17 is reduced to  $\frac{\rho Z_{n2}}{1 + \rho}$

where  $\rho$  is the ratio of cross-polarizing voltage to self-voltage measured under healthy line conditions. As an example,  $\rho$  is 2% in the type YTG distance relay.

An improved partially cross-polarized mho characteristic can be obtained by converting the cross-polarizing voltage to a square wave before mixing a proportion of it with the sine wave self-polarizing voltage. This simple process shapes the characteristic in such a way as to increase the resistive expansion of the characteristic along the  $R$  axis whilst restricting the expansion in the third and fourth quadrants of the  $X/R$  diagram.

The 'shield'-shaped characteristic so produced is shown in Figure 11.19. It has phase selection properties close to those of a conventional partially cross-polarized mho, and fault resistance coverage close to that of a fully cross-polarized mho. The shaped characteristic is used in both 'Micromho' and 'Quadramho', where  $\rho$  is 16% measured on peak values.

#### 11.17

##### 11.17.1.1

During severe power swing conditions from which the system is unlikely to recover, normal service can be maintained only if the swinging sources are separated. Ideally, the split should be made so that the plant capacity and connected loads on either side of the split are matched.

Ordinary distance schemes cannot be relied upon to detect and isolate this type of disturbance correctly, so, as previously mentioned, it is often necessary to prevent these schemes from operating, to avoid cascade tripping. In order to ensure the separation of the system at a selected point, minimizing the disturbance to the system, an out-of-step tripping scheme using ohm units is employed.

The out-of-step tripping scheme consists basically of two ohm units, the characteristics of which are arranged to be parallel to and on either side of the line impedance vector, as shown in Figure 11.20.

The relay characteristic divides the impedance diagram into three zones,  $J$ ,  $K$  and  $L$ . As the impedance changes during a power swing, the point representing the impedance moves along the swing locus, entering the three zones in turn and causing the ohm units and their associated auxiliary relays to operate. When the impedance enters the third zone the trip sequence is completed and the circuit breaker trip coil is energized.

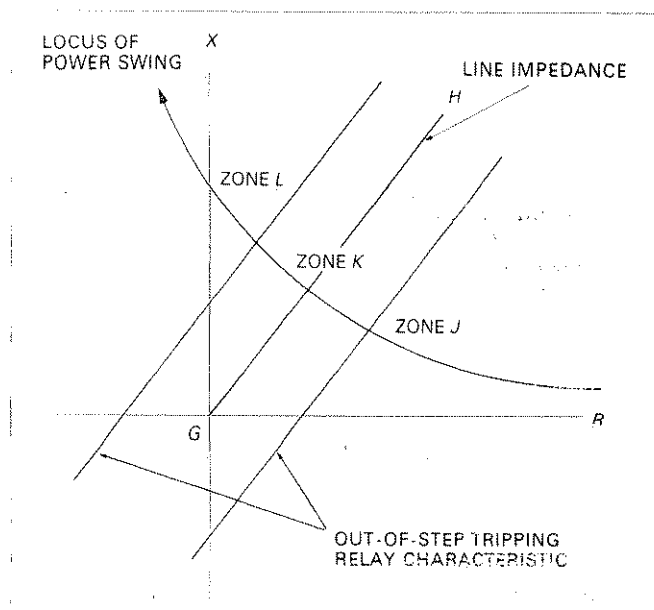


Figure 11.20 Application of out-of-step tripping relay characteristic.

As no condition other than a power swing can cause the impedance vector to move successively through the three zones, the scheme is entirely safe from operation on any other type of system disturbance, for instance power system fault conditions.

#### 11.18

##### DISTANCE SCHEMES

Discriminating zones of protection can be obtained using distance relays, provided that fault distance is a simple function of impedance. While this is true in principle for transmission circuits, the impedances actually measured depend on the magnitudes of current and voltage, the relay connections, the type of fault and impedance in the fault, in addition to the line impedance and circuit configuration, whether on single or double circuit lines. It is impossible to eliminate these additional factors in distance measurement for all possible operating conditions. However, a considerable measure of success can be achieved with composite distance schemes comprising starting relays, distance measuring relays, auxiliary relays, zone timers and tripping relays.

To cater for the economic and technical requirements of any particular power system, a number of schemes are available. These are described in detail in Chapter 12.

The basic scheme provides plain distance protection incorporating several steps (zones) of protection to cover the line and provide back-up protection for adjacent lines. Other schemes are of the unit type and use a combination of distance measurement with high speed signalling such as power line carrier, voice frequency or microwave to provide fast clearance of faults anywhere on the protected line. Schemes of this type often incorporate basic scheme facilities as well as unit protection.

Distance schemes may be formed using separate relays wired together or may be provided within a single composite distance relay. For example recent designs of distance relays such as Micromho and Quadramho have all the necessary measuring, logic, time delay and auxiliary elements built in as standard and the required scheme can be selected on site by switches on the front of the relay.

Full distance or switched distance protection schemes may be applied according to the system voltage and the importance of the lines to be protected. The main difference between the two arrangements is that the full distance scheme uses six measuring units per zone, three for phase faults and three for earth faults, whereas in a typical switched distance scheme only one measuring unit is used for all types of faults. This single measuring unit is switched to the correct fault loop impedance by means of a suitable set of starting units of the overcurrent or under-impedance type.

On high voltage and extra high voltage transmission lines where fast fault clearance and high reliability are vital and low cost is not such an important factor, 'full scheme' distance relays have always been used. These usually have separate measuring units for each of the three zones, and for each of the 6 'phases' of measurement. All 18 measuring units operate independently, with no need for starting relays, so the Zone 1 trip time is inherently faster than that of a switched relay. There is also a greater degree of redundancy and hence better reliability in a full-scheme design.

Distance schemes designed for use on distribution lines have traditionally been of the switched distance type, in which, for reasons of economy, the same measuring element is used for Zone 1, Zone 2 and Zone 3. Such designs need starting elements which are used as phase selectors for the measuring element and also to start the zone timers controlling the reach setting. By using modern digital electronics, the cost of a measuring unit has been reduced to the point where there is no longer any significant advantage in using the switched principle in a new design. An example of this is the Quadramho relay which is a new

Compact and economical full scheme relay specifically designed with transmission and distribution lines in mind.

## 11.19 STARTING ELEMENTS FOR SWITCHED DISTANCE PROTECTION

Switched distance relays require starting elements for phase selection and to start zone timers. The phase selectors should be sensitive enough to detect faults occurring in the third zone under minimum generating conditions, but capable of discriminating between these and maximum load transfer.

A number of different characteristics can be used for the starting elements, the most common being Overcurrent, Impedance, Offset Mho and Lenticular. The choice of starter is dependent on power system parameters such as maximum load transfer in relation to maximum reach required and power system earthing arrangements.

Where overcurrent starters are in use, care must be taken to ensure that under light load conditions, that is, with minimum generating plant, the setting of the overcurrent starters is sensitive enough to detect faults beyond the third zone. Furthermore, these starters should have a high drop-off to pick-up ratio, to ensure that they will drop off under maximum load conditions after a second or third zone fault has been cleared by the first zone relay in the faulty section. Without this feature indiscriminate tripping may result for subsequent faults in the second or third zone. The overcurrent starters operate the timer for controlling the second and third zone reach, which, if allowed to run on, would modify the reach setting, so that on the occurrence of a second fault any such relay in the system would be likely to operate. It will be seen that with a fault at point *F* in Figure 11.21 circuit breaker *M* would trip on first zone distance, but the overcurrent starting relays would pick up at breakers *G* and *J* and with a low reset ratio might be held closed by the load fed off at *L*<sub>1</sub> and *L*<sub>2</sub> respectively. If circuit breaker *M* were then reclosed on to the fault, breakers *G*, *J* or *M* might trip if sufficient time had elapsed to allow the distance relay at breakers *G* and *J* to extend their reach into the fault.

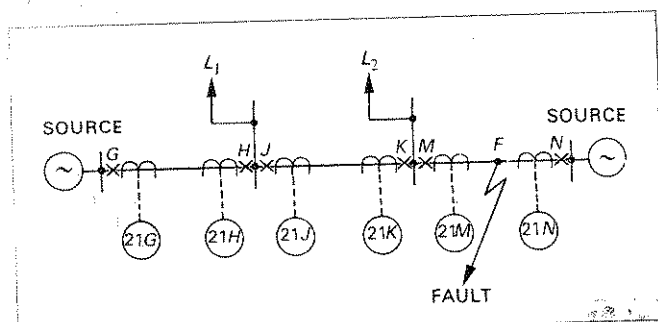


Figure 11.21 Example of application of distance relays with overcurrent starters.

For satisfactory operation of the overcurrent starters in a switched distance scheme, the following conditions must be fulfilled:

- The current setting of the overcurrent starters must be not less than 1.2 times the maximum full load current of the protected line.
- The power system minimum fault current for a fault at the Zone 3 reach of the distance relay must not be less than 1.5 times the setting of the overcurrent starters.

On multiple-earthed systems where the neutrals of all the power transformers are solidly earthed, or in power systems where the fault current is less than the full load current of the protected line, it is not possible to use overcurrent starters. In these circumstances under-impedance starters having impedance, offset mho or lenticular characteristics must be used.

the maximum expected load current and equivalent minimum load impedance in relation to the required relay setting to cover faults in Zone 3. This is illustrated in Figure 11.15 where  $Z_{D1}$ ,  $Z_{D2}$ , and  $Z_{D3}$  are respectively the minimum load impedance permitted when lenticular, offset mho and impedance relays are used.

## 11.20 RELAY

When considering the application of distance relays to power systems, three main factors must be known: the line impedances, the minimum voltage for a fault at the reach of the distance relay, and the minimum fault current.

Sequence impedances used in the analysis of power system faults are shown in Figure 11.22, and it is important to bear in mind that for static equipment, such as power transformers and transmission lines, the positive sequence impedance is always equal to the negative sequence impedance. In the construction of the sequence networks, the positive sequence impedances of all items of equipment are always present for all types of faults, while the zero sequence impedances are only in evidence during earth faults.

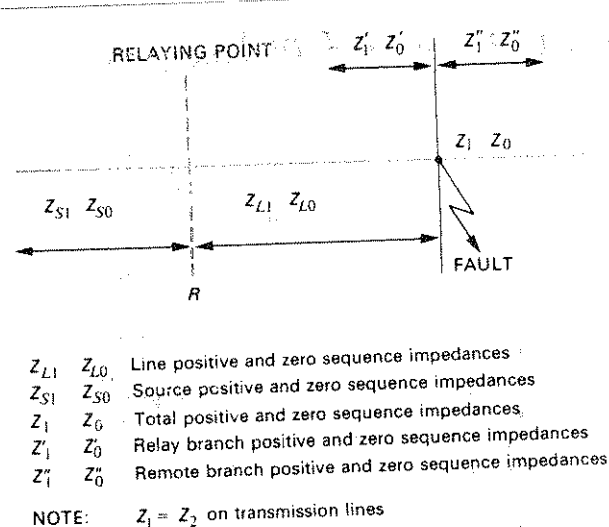


Figure 11.22 Impedances involved in distance measurement.

There are four types of shunt faults which can occur in a three-phase system. These are illustrated in Figure 11.23, which shows that the combinations of the phases involved by the faults are:

|                       |       |         |
|-----------------------|-------|---------|
| Three phase           | A-B-C | A-B-C-E |
| Double phase to earth | A-B-E | B-C-E   |
| Double phase          | A-B   | B-C     |
| Single phase to earth | A-E   | B-E     |

There are also combinations of shunt faults which could occur in adjacent feeders, normally known as 'cross-country' faults, and combinations of shunt and series faults, such as a conductor falling to the ground, resulting in an open circuit and short circuit in the phase at the same location. This latter group of faults is normally not considered when applying distance protection, since no relay can be expected to measure fault distance correctly for them.

An examination of voltages at the fault, using Figure 11.23, shows that for phase faults the difference of the phase to earth voltages is zero, while for earth faults the phase to earth voltage is zero. If measurement of fault distance is to be accomplished with reasonable accuracy, the voltage at the relay terminals must be proportional to the voltage drop to the fault. For this reason, measurement of all faults is not

possible using a single measuring element and it is usual to employ three measuring relays for earth faults and three measuring relays for phase faults, that is, one for each phase and pair of phases. Each of the measuring elements is supplied with input quantities suitable for correct distance measurement in its associated phases.

## 11.21

In Figure 11.24 the currents and voltages at the relaying point for three-phase and double phase faults, as illustrated in Figure 11.23, are given in terms of the positive sequence impedances  $Z_{S1}$  and  $Z_{L1}$  in the source and line sides of the relay location and the positive sequence current  $I'_1$  in the 'a' phase entering the fault through the relay location.

It can be seen that while for three-phase faults the phase voltages at the relaying point are dependent on the product of the line impedance and positive sequence current, for double phase faults they are functions of source impedance. This latter dependence on  $Z_{S1}$  is eliminated by applying the difference of the phase voltages to the relay. For example:

$$V'_{bc} = (a^2 - a) Z_{L1} I'_1 \quad (\text{for three-phase faults}).$$

$$V'_{bc} = 2(a^2 - a) Z_{L1} I'_1 \quad (\text{for double phase faults}).$$

Distance measuring elements are usually calibrated in terms of the positive sequence impedance. Correct measurement for both phase to phase and three phase faults is achieved by supplying each phase to phase measuring element with its corresponding phase to phase voltage and difference in phase currents.

Thus for the B-C element, the current measured will be:

$$I'_b - I'_c = (a^2 - a) I'_1 \quad (\text{for three-phase faults}).$$

$$I'_b - I'_c = 2(a^2 - a) I'_1 \quad (\text{for double phase faults}).$$

and the relay will measure  $Z_{L1}$  in each case.

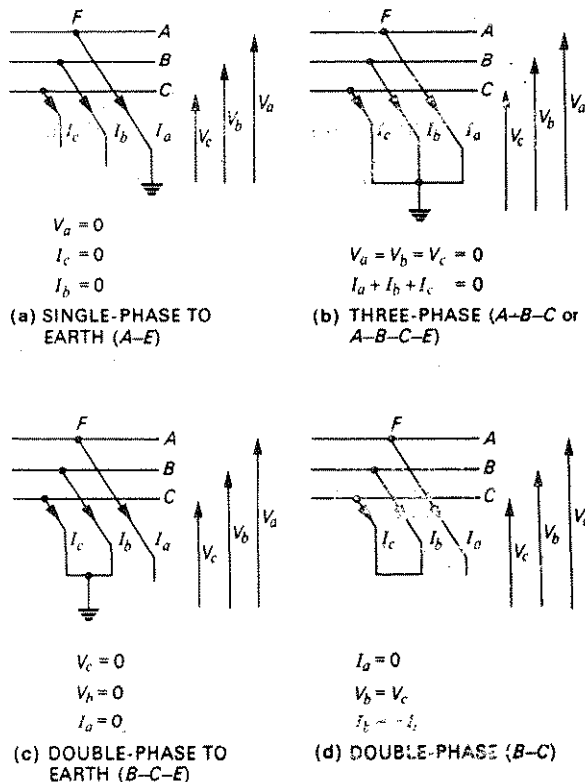


Figure 11.23 Current and voltage relations in fault branch for various shunt faults.

| Fault quantity | Three-phase (A-B-C) | Double phase (B-C)            |
|----------------|---------------------|-------------------------------|
| $I'_a$         | $I'_1$              | 0                             |
| $I'_b$         | $a^2 I'_1$          | $(a^2 - a) I'_1$              |
| $I'_c$         | $a I'_1$            | $(a - a^2) I'_1$              |
| $V'_a$         | $Z_{L1} I'_1$       | $2(Z_{S1} + Z_{L1}) I'_1$     |
| $V'_b$         | $a^2 Z_{L1} I'_1$   | $(2a^2 Z_{L1} - Z_{S1}) I'_1$ |
| $V'_c$         | $a Z_{L1} I'_1$     | $(2a Z_{L1} - Z_{S1}) I'_1$   |

NOTE:  $I'_1 = \frac{1}{3}(I'_a + a I'_b + a^2 I'_c)$

$I'$  and  $V'$  are at relay location

Figure 11.24 Phase currents and voltages at relaying point due to phase faults.

## 11.22

### EARTH FAULTS

When an earth fault occurs, the phase to earth voltage at the fault location is zero, and it would appear that the voltage drop to the fault is a straight-forward product of the phase current and the line impedance. This is not the case, because the current in the fault loop depends on the number of earthing points, the method of earthing and the sequence impedances of the fault loop.

The voltage drop to the fault is the sum of the sequence voltage drops between the relaying point and the fault, that is:

$$V'_a = I'_1 Z_{L1} + I'_2 Z_{L1} + I'_0 Z_{L0}$$

The current in the fault loop is given by:

$$I'_a = I'_1 + I'_2 + I'_0$$

and the residual current  $I'_N$  at the relaying point is given by:

$$I'_N = I'_a + I'_b + I'_c = 3I'_0$$

where  $I'_a$ ,  $I'_b$  and  $I'_c$  are the phase currents at the relaying point. From the above expressions the voltage at the relaying point can be expressed in terms of the phase currents at the relaying point, the transmission line zero sequence to positive sequence impedance ratio  $K$ , equivalent to  $Z_{L0}/Z_{L1}$ , and the positive sequence line impedance  $Z_{L1}$ .

$$V'_a = Z_{L1} \left\{ I'_a + (I'_a + I'_b + I'_c) \frac{K-1}{3} \right\} \quad \dots \text{Equation 11.7}$$

The voltage appearing at the relaying point, as previously mentioned, varies with the number of infeeds, the method of system earthing and the position of the relay relative to the infeed and earthing points in the system. Figure 11.25 illustrates the three possible arrangements which can occur in practice with a single infeed. In Figure 11.25(a) the healthy phase currents are zero, that is,  $I'_a I'_b I'_c$  is 1-0-0, so the impedance seen by a relay comparing  $I'_a$  and  $V'_a$  is given by:

$$Z = \left\{ 1 + \frac{(K-1)}{3} \right\} Z_{L1} \quad \dots \text{Equation 11.8}$$

In Figure 11.25(b) the currents entering the fault from the relay branch have a 2-1-1 current distribution, so:

$$Z = Z_{L1}$$

In Figure 11.25(c), the phase currents have a 1-1-1 current distribution and hence:

$$Z = K Z_{L1}$$

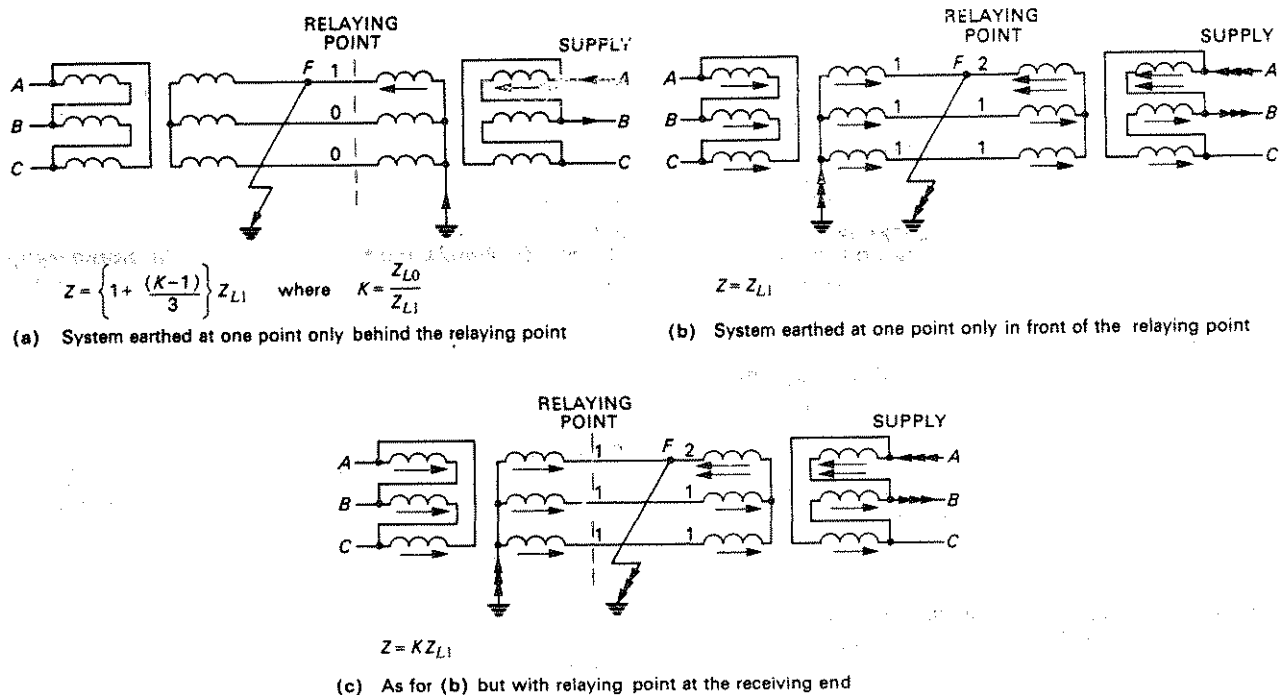


Figure 11.25 Effect of infeed and earthing arrangements on earth fault distance measurement.

If there were infeeds at both ends of the line section, the impedance measured would be a superposition of any two of the above examples, with the relative magnitudes of infeeds taken into account.

This analysis shows that the relay can only measure an impedance which is independent of infeed and earthing arrangements if a proportion  $K_N = (K-1)/3$  of the residual current  $I_N = I_a + I_b + I_c$  is added to the phase current  $I_a$ . This technique is known as 'residual compensation'.

Most distance relays compensate for the earth fault conditions by using an additional replica impedance  $Z_N$  within the measuring circuits. Whereas the phase replica impedance  $Z_1$  is fed with the phase current at the relaying point,  $Z_N$  is fed with the full residual current. This is shown in simplified form in Figure 11.26.

The value of  $Z_N$  is adjusted so that for a fault at the reach point the sum of the voltages developed across  $Z_1$  and  $Z_N$  equals the measured phase to neutral voltage in the faulted phase.

The required setting for  $Z_N$  can be determined by considering an earth fault at the reach point of the relay. This is illustrated with reference to the A-N fault with single earthing point behind the relay as in Figure 11.25(a).

Voltage supplied from the VTs

$$= I_1(Z_1 + Z_2 + Z_0) = I_1(2Z_1 + Z_0)$$

Voltage across replica impedances

$$= I_A Z_1 + I_N Z_N$$

$$= I_A(Z_1 + Z_N) = 3I_1(Z_1 + Z_N)$$

The required setting of  $Z_N$  for balance at the reach point is given from:

$$3I_1(Z_1 + Z_N) = I_1(2Z_1 + Z_0)$$

$$\therefore Z_N = \frac{Z_0 - Z_1}{3}$$

$$= \frac{(Z_0 - Z_1)}{3Z_1} Z_1 = K_N Z_1 \quad \dots \text{Equation 11.9}$$

With replica impedance set to  $\frac{Z_0 - Z_1}{3}$ , earth fault measuring elements will measure the fault impedance correctly irrespective of the number of infeeds and earthing points on the system.

The factor  $K$ , as previously mentioned, is a constant for a given line configuration and earth resistivity. For example, a typical value of  $K$  for 33 kV lines is 4 and for 132 kV lines, 2.5. This means that the compensation  $K_N$  necessary in the above cases is 100% and 50% respectively.

The chart in Figure 11.27 gives line positive and zero sequence impedances for various line configurations at 132 kV, allowance being made for variation in earth resistivity, together with the compensation to be applied in each case.

### 11.23

#### MINIMUM VOLTAGE AT RELAY TERMINALS

With a knowledge of the sequence impedances involved in the fault or alternatively, the fault MVA, the system voltage and the earthing arrangements, it is possible to calculate the minimum voltage at the relay terminals for a fault at the reach point of the relay. It is then only necessary to compare this voltage with the relay voltage/reach curve to establish the suitability of a particular relay for a given application.

Information on fault current levels are quoted in two distinct ways, according to whether phase faults or earth faults are to be considered. First, for phase faults, the fault level is given in terms of three-phase fault MVA at system voltage and secondly, for earth faults, the faulty phase and healthy phase currents are given for a fault at a selected point in the protected section. The procedure for calculating the minimum voltage at the relay terminals is as follows:

#### Phase faults

a. Given minimum MVA fault level at relaying point, calculate source positive sequence impedance:

$$Z_{S1} = \frac{(\text{kV})^2}{\text{MVA}} \text{ ohms}$$

...Equation 11.10

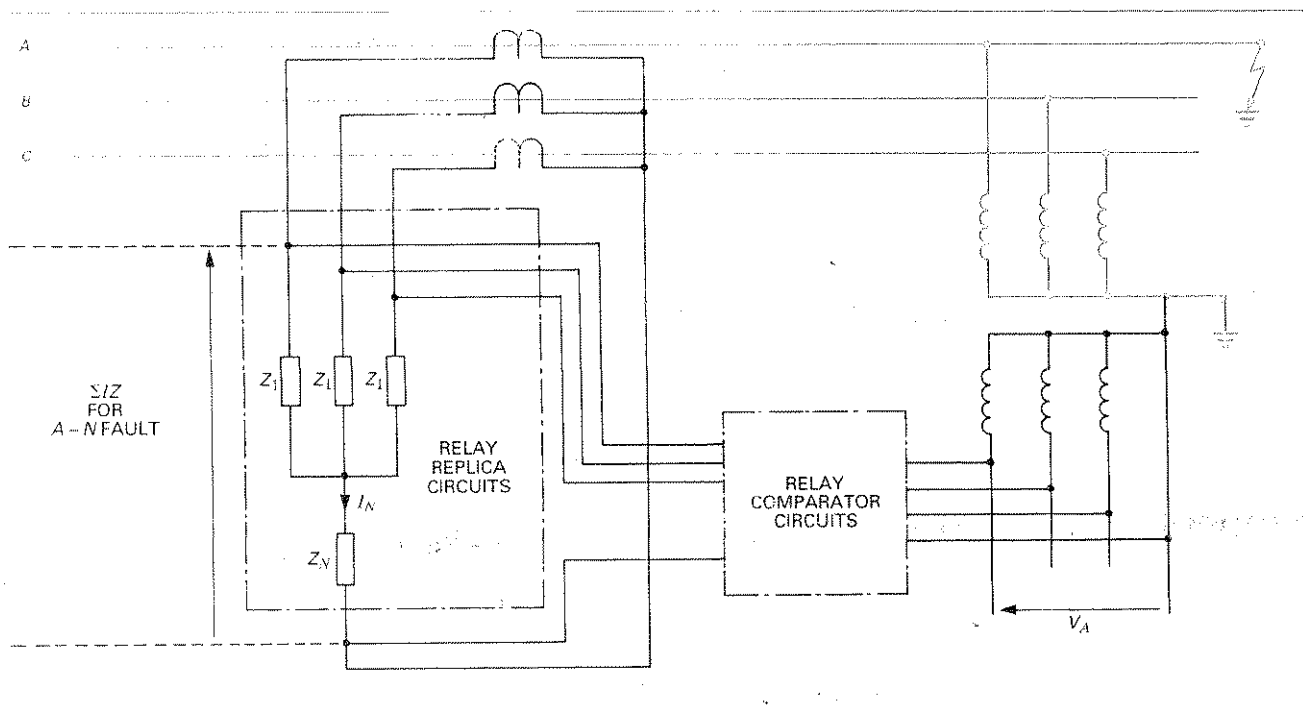


Figure 11.26 Earth fault relay current and voltage circuits.

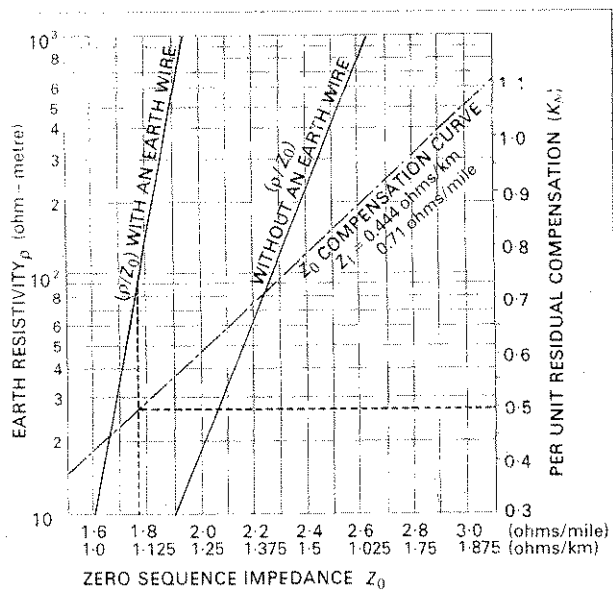


Figure 11.27 Compensation/zero sequence impedance/resistivity chart for a typical 132 kV transmission line.

Where kV is the phase to phase voltage and MVA is the three-phase fault MVA.

b. Calculate impedance of line corresponding to the required reach setting:

$$Z_{L1} = z_1 L \text{ ohms} \quad \dots \text{Equation 11.11}$$

Where  $Z_{L1}$  is the positive sequence line impedance up to the reach setting.

$z_1$  is the positive sequence line impedance in ohms/unit length of line.

$L$  is the length of line between the relay and required reach point.

c. Calculate fault current  $I'_F$  entering the fault from the relay branch:

$$I'_F = \frac{\text{kV} \times 10^3}{\sqrt{3} (Z_{S1} + Z_{L1})} \text{ amperes} \quad \dots \text{Equation 11.12}$$

d. Given the minimum MVA fault level at 'reach' point together with the ratio  $C_1$  (positive sequence distribution factor) of the current entering the fault from the relay branch and the total fault current, an alternative method of calculating  $I'_F$  can be used:

$$I'_F = C_1 \frac{\text{MVA} \times 10^3}{\sqrt{3} \text{ kV}} \text{ amperes} \quad \dots \text{Equation 11.13}$$

e. The minimum voltage for a phase fault occurs on three-phase faults. Using  $I'_F$  calculated either by (c) or (d) and  $Z_{L1}$  calculated from (b) the phase to phase voltage at the relay terminals is given by:

$$V_R = \frac{\sqrt{3} Z_{L1} I'_F}{\text{VT ratio}} \text{ volts} = \frac{Z_{L1} \times \text{kV}}{(Z_{S1} + Z_{L1}) \sqrt{3} \text{ ohms/km}} \quad \dots \text{Equation 11.14}$$

### Earth faults

a. From transmission line data calculate line  $Z_0/Z_1$  ratio  $K$ :

$$K = Z_{L0}/Z_{L1}$$

b. Given the phase currents in the relay branch, calculate the residual current  $I'_N$  entering the fault from the relay branch:

$$I'_N = I'_a + I'_b + I'_c$$

where  $I'_a$ ,  $I'_b$  and  $I'_c$  are the phase currents.

c. Calculate  $Z_{L1}$  corresponding to the required reach setting:

$$Z_{L1} = z_1 L \text{ ohms}$$

where  $Z_{L1}$  is the positive sequence line impedance up to the reach setting.

$z_1$  is the positive sequence line impedance in ohms/unit length of line.

$L$  is the length of line between the relay and required reach point.

d. Designating the fault current in the faulty phase entering the fault from the relay branch as  $I'_F$ , the voltage at the relay terminals is:



$$V_R = Z_{L1} \frac{I_F + (I_N/3)(K-1)}{\text{VT ratio}} \text{ volts} \quad \dots \text{Equation 11.15}$$

For a radial feeder which is earthed at one point only behind the relay location,  $I_N = I_F = I_F$  and

$$V_R = \frac{Z_{L1} \cdot I_F \left\{ 1 + \frac{(K-1)}{3} \right\}}{\text{VT ratio}}$$

$$= \frac{I_F Z_{Le}}{\text{VT ratio}}$$

where  $Z_{Le}$  is the earth loop impedance of the protected line up to the required reach point

$$\text{and } Z_{Le} = \frac{Z_{L1} + Z_{L2} + Z_{L0}}{3}$$

e. Where the method of earthing at both ends of the line section is known  $I_N$  may be calculated as follows:

$$I_1 = I_2 = I_0 \text{ at the fault.}$$

Calculate  $Z_1$  as viewed from the fault:

$$Z_1 = \frac{Z'_1 Z''_1}{Z'_1 + Z''_1}$$

where  $Z'_1$  is the positive sequence impedance of relay branch, that is  $(Z_{S1} + Z_{L1})$ .

$Z''_1$  is the impedance of the remote branch.

NOTE: All source positive sequence impedances are calculated assuming minimum MVA fault conditions.

Similarly:

$$Z_0 = \frac{Z'_0 Z''_0}{Z'_0 + Z''_0}$$

where  $Z'_0$  is the zero sequence impedance of relay branch, that is  $(Z_{S0} + Z_{L0})$ .

$Z''_0$  is the impedance of the remote branch.

NOTE: Source zero sequence impedances must take account of line impedance, transformer impedances and so on, behind the infeed points of the line section.

Where the line section is earthed at one point only, behind the relaying point:

$$Z_0 = Z_{S0} + Z_{L0}$$

Calculate  $I_0$  from the formula:

$$I_0 = \frac{\text{kV} \times 10^3}{\sqrt{3} (2Z_1 + Z_0)} \quad \dots \text{Equation 11.17}$$

where  $I_0$  is the zero sequence current in the fault.

kV is the system voltage.

The residual current entering the fault from the relay branch is therefore:

$$I'_N = 3C_0 I_0$$

where  $C_0 = Z_0/Z'_0$

f. The current  $I'_F$  in the faulty phase in the relay branch may be calculated as follows:

$$I'_F = (2C_1 + C_0) I_0 \quad \dots \text{Equation 11.18}$$

where  $C_1 = Z_1/Z'_1$

g. The minimum voltage at the relay terminals may now be calculated by the formula given in (d) above.

## 11.24

Distance relays are calibrated in secondary ohms and are set to measure the positive sequence impedance of the line section. Modern relays have typical ranges such as:

0.2–240 ohms (1 A basis)  
0.04–48 ohms (5 A basis)

Current and voltage transformers have standard ratings, which are usually 1 A and 5 A for current transformers and 100, 110, 115 and 120 volts for voltage transformers.

To establish the setting of a relay, it is first necessary to calculate in primary ohms, the desired 'reach' of the relay along a line section. As previously mentioned, this is usually 80% of the line section. The secondary ohms may then be calculated using the relationship:

$$Z_s = Z_p \frac{\text{CT ratio}}{\text{VT ratio}} \quad \dots \text{Equation 11.19}$$

The secondary value thus obtained should fall within the relay setting range. When reactance relays are chosen, the setting calculations are carried out using the reactance constants of the transmission lines. When mho relays are employed the difference between the line angle and the desired relay characteristic angle must be taken into account when calculating the relay setting.

## 11.25

### MINIMUM LENGTH OF LINE

To determine the minimum length of line that can be protected by a distance relay it is necessary to check first, that the minimum voltage seen by the relay for a fault at the Zone 1 reach is within the declared sensitivity for the relay and secondly, that the secondary ohmic impedance of the line for Zone 1 reach falls within the ohmic setting of the relay.

Assuming a relay sensitivity of  $V_R$  volts for a  $\pm 5\%$  accuracy in measurement, the minimum length of line may be determined from Equations 11.14, 11.15 and 11.16.

For example; the minimum line length to which a relay with sensitivity of 3 volts and Zone 1 setting of 80% may be applied may be calculated as follows:

For phase faults, from Equation 11.14

$$3 = \frac{\sqrt{3} \times 0.8 \times z_1 \times L_m \times I'_F}{\text{VT ratio}}$$

$$L_m = 2.17 \frac{\text{VT ratio}}{z_1 \cdot I'_F}$$

For earth faults, from Equation 11.15

$$3 = \frac{0.8 z_1 L_m \left\{ I'_F + \frac{I'_N}{3} (K-1) \right\}}{\text{VT ratio}}$$

$$L_m = 3.75 \frac{\text{VT ratio}}{z_1 L_m \left\{ I'_F + \frac{I'_N}{3} (K-1) \right\}}$$

For earth faults on a radial feeder with single point earthing behind the relay, from Equation 11.16:

$$3 = \frac{0.8 z_e L_m \cdot I'_F}{\text{VT ratio}}$$

$$L_m = 3.75 \frac{\text{VT ratio}}{z_e \cdot I'_F}$$

where  $L_m$  = the minimum line length to the remote busbars of the protected line

$z_e$  = the earth loop impedance of the protected line in ohms/unit length of line.

A distance relay is said to under-reach when the impedance presented to it is greater than the apparent impedance to the fault.

Percentage under-reach is defined as:

$$\frac{Z_R - Z_F}{Z_R} \times 100\% \quad \dots \text{Equation 11.20}$$

where  $Z_R$  = relay reach setting

$Z_F$  = effective reach.

Two examples of under-reaching are the uncompensated earth fault relay and the effect of current infeed from remote busbars between the relay and fault positions.

### i. Uncompensated earth fault relay.

Consider the relay setting to be  $Z_{L1}$ .

The impedance seen by an uncompensated relay for a fault at  $Z_{L1}$

$$= \left\{ 1 + \frac{(K-1)}{3} \right\} Z_{L1}$$

which is greater than  $Z_{L1}$ .

Since the relay will operate only when the impedance presented to the relay is  $Z_{L1}$  the effective reach will be

$$\frac{Z_{L1}}{1 + \left( \frac{K-1}{3} \right)} \quad \dots \text{Equation 11.21}$$

The percentage under-reach =

$$\frac{Z_{L1} - \frac{Z_{L1}}{1 + \left( \frac{K-1}{3} \right)}}{Z_{L1}} \times 100\% = \frac{(K-1)}{(K+2)} \times 100\%$$

As shown in Section 11.22, this effect is avoided by using residual or zero sequence compensation.

### ii. Effect of remote infeeds.

In Figure 11.28, the relay at G will not measure the correct impedance for a fault on line section  $Z_K$  due to current infeed  $I_J$ . Consider a relay setting of  $Z_G + Z_K$ .

For a fault at point F, the relay is presented with an impedance

$$Z_G + \frac{I_G + I_J}{I_G} \cdot x \cdot Z_K$$

So, for relay balance:

$$Z_G + Z_K = Z_G + \frac{(I_G + I_J)}{I_G} \cdot x \cdot Z_K$$

$$\therefore x = \frac{I_G}{I_G + I_J}$$

Therefore the effective reach

$$= Z_G + \left( \frac{I_G}{I_G + I_J} \right) \cdot Z_K \quad \dots \text{Equation 11.22}$$

Percentage under-reach

$$\begin{aligned} & \frac{Z_G + Z_K - Z_G - \left( \frac{I_G}{I_G + I_J} \right) \cdot Z_K}{Z_G + Z_K} \times 100\% \\ &= \left( \frac{I_J}{I_G + I_J} \right) \cdot \frac{Z_K}{Z_G + Z_K} \times 100\% \end{aligned}$$

To ensure that the relay will see the fault at F, the reach setting would need to be extended to

$$Z_G + \frac{(I_G + I_J) \cdot Z_K}{I_G}$$

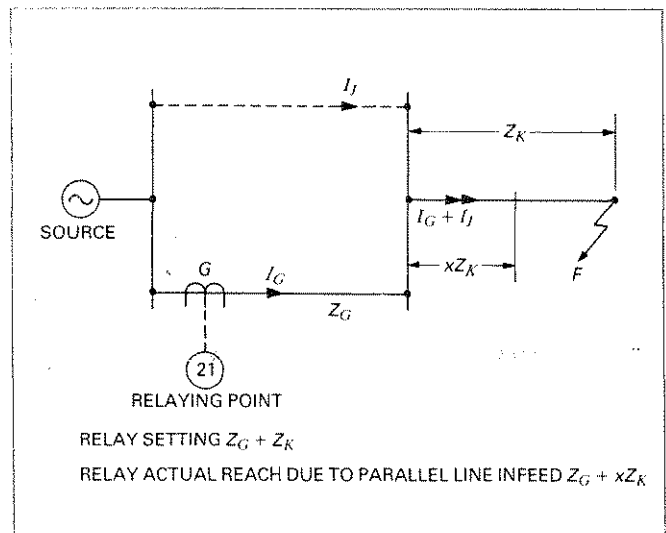


Figure 11.28 Effect on distance relays of infeed at the remote busbar.

When setting remote back-up protection, care should be taken that the setting used does not result in the relay operating due to a load condition when the source of remote infeed is reduced. For example, if  $I_J = 9I_G$ , the required setting to see faults at F would be  $Z_G + 10Z_K$  which would also be the effective setting if current  $I_J$  is removed.

Care should also be taken that large forward reach settings will not result in operation of sound phase relays for reverse earth faults. See Section 11.28.

### 11.27 OVER-REACH

A distance relay is said to over-reach when the impedance presented to it is less than the apparent impedance to the fault.

Percentage over-reach is defined as:

$$\frac{Z_F - Z_R}{Z_R} \times 100\% \quad \dots \text{Equation 11.23}$$

where  $Z_R$  = relay reach setting

$Z_F$  = effective reach.

An example of the over-reaching effect is when distance relays are applied on parallel lines and one line is taken out of service and earthed at each end. In this condition the effect of mutual coupling between lines causes the relay at one end of the in-service line to over-reach. This is shown in Figure 11.29.

Consider a fault at F and relay setting  $Z_{L1}$ , where x is the per unit distance of the fault beyond the remote busbars.

Zero sequence current induced in line H is  $I_{H0}$ :

$$I_{H0} = I_{G0} \cdot \frac{Z_{0M}}{Z_{L0}}$$

Voltage measured by the relay:

$$\begin{aligned} V_{GR} &= (1+x)(2I_{G1}Z_{L1} + I_{G0}Z_{L0}) - I_{H0}Z_{0M} \\ &= I_{G0} \left\{ (1+x)(2Z_{L1} + Z_{L0}) - \frac{Z_{0M}^2}{Z_{L0}} \right\} \end{aligned}$$

Current measured by the relay:

$$I_{GR} = I_G + I_{G0}(K-1)$$

where  $K = \frac{Z_{L0}}{Z_{L1}}$

Therefore

$$I_{GR} = 2I_{G1} + I_{G0} \cdot K$$

*Handwritten note:*  $K = \frac{Z_{L0}}{Z_{L1}} = 26.2$

Impedance measured

$$\begin{aligned} &= \frac{V_{GR}}{I_{GR}} \\ &= Z_{L1} \left\{ (1 + x) - \frac{Z_{OM}^2}{Z_{L0}(2Z_{L1} + Z_{L0})} \right\} \dots \text{Equation 11.24} \end{aligned}$$

For relay balance

$$Z_{L1} = Z_{L1} \left\{ 1 + x - \frac{Z_{0M}^2}{Z_{L0}(2Z_{L1} + Z_{L0})} \right\}$$

$$\therefore x = \frac{Z_{0M}^2}{Z_{L0}(2Z_{L1} + Z_{L0})}$$

Therefore the effective reach is  $(1 + x) Z_{L1}$ .

Percentage over-reach

$$= \frac{(1+x)Z_{L1} - Z_{L1}}{Z_{L1}} \times 100\%$$
$$= x \cdot 100\%.$$

For a typical 400 kV line,  $Z_{0M} = 0.4$ ,  $Z_{L1} = 0.26$ ;  $Z_{L0} = 0.76$  in ohms/km.

$$\therefore x = 0.164.$$

$$\therefore \text{Percentage over-reach} = 16.4\%$$

In order to overcome this possible over-reaching effect some power supply authorities reduce the reach of earth fault relays to around  $0.65 Z_{L1}$  when lines are taken out for maintenance. However, the probability of having a fault on the first section of the following line while one line is out of service is very small and many authorities do not reduce the setting under this condition.

It should be noted that the use of mutual compensation will not overcome the over-reaching effect since earthing clamps are normally placed on the line side of the current transformers.

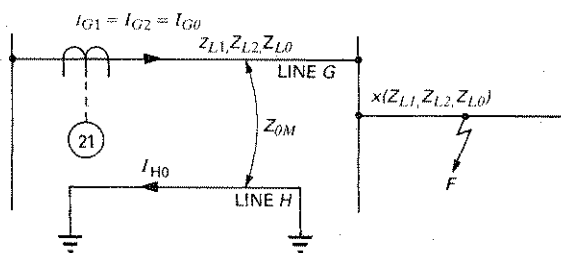


**Figure 11.29** Over-reaching on parallel lines due to mutual coupling with one line out of service and earthed at each end.

## 11.28

#### FORWARD REACH LIMITATIONS

There is a limitation on the maximum forward reach setting which can be applied to a distance relay. The relay must not operate under maximum load conditions and also, if the reach is too long, the healthy phase earth fault units may operate for heavy reverse faults.

Figure 11.30 shows the basic circuit for a reverse earth fault and from this it can be seen that the fault current in the line for an earth fault at  $F$  is given by:

$$I_F = \frac{E}{Z_s + Z_{L_c}} \text{ (secondary amperes)}$$

where  $E$  = system phase to neutral voltage (secondary volts).

$Z_s$  = source impedance (secondary ohms).

$Z_{Le}$  = line earth fault loop impedance (secondary ohms).

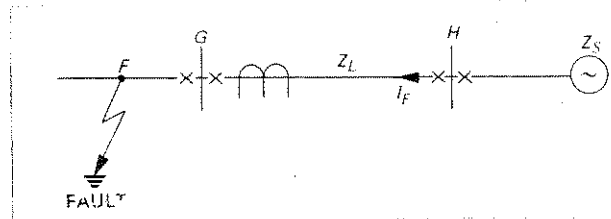


Figure 11.30 Basic primary circuit for reversed earth fault.

The current, in secondary amperes, required to operate one of the healthy phase mho units depends on the relay ohmic setting, the relay characteristic angle, the amount of earth fault compensation, and the phase angle of the fault current. This can be appreciated from Figure 11.31 which shows the characteristics of self-polarized mho units applied to both faulty and healthy phases.

The current, in secondary amperes, required to operate the healthy phase relay is given by:

$$I_S = \frac{100E}{K_N Z_R \cos(60^\circ - \alpha)}$$

where  $K_N$  = percentage residual earth fault compensation

$$= \left\{ \frac{Z_0}{Z_1} - 1 \right\} \frac{100}{3}$$

 $Z_R$  = relay setting (secondary ohms).

$\alpha$  = difference in angle between relay characteristic angle and fault current angle.

In order to avoid maloperation for reverse earth faults,  $I_S$  must be greater than  $I_F$ , that is:

$$\frac{K_N}{100} Z_R \cos (60^\circ - \alpha) < Z_S + Z_{Le}$$

$$\text{or } Z_R < \frac{(Z_S + Z_{Lr}) 100}{K_N \cos (60^\circ - \alpha)} \quad \dots \text{Equation 11.25}$$

If the RCA is assumed to be equal to the line fault angle and a value of 50% is taken for the earth fault compensation, the relay setting  $Z_R$  for the Zone 3 reach of the over-reaching mho units in a blocking scheme should be set to be in accordance with the following inequality:

$$Z_B < 4(Z_S + Z_{LV})$$

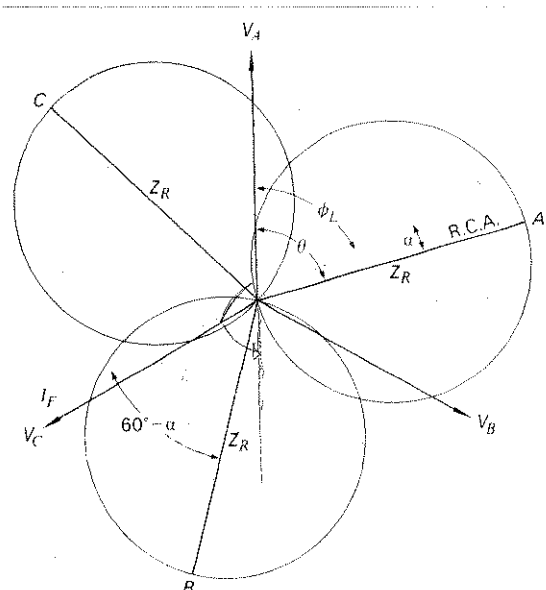


**Figure 11.31** Vector diagram of *mho* unit characteristics for a reversed phase A to earth fault.

## 11.29

### MUTUAL COMPENSATION APPLIED TO CLOSE RELAYS PROTECTING TWIN CIRCUIT PARALLEL OVERHEAD LINES

Analysis of an earth fault on one circuit of a parallel overhead line shows that a distance relay at one end of the faulty line will tend to over-reach while that at the other end will tend to under-reach. In most applications the degree of under-reach is acceptable, but in cases of long lines with high mutual inductance mutual zero sequence compensation can be used to improve protection coverage.

Referring to Figure 11.32, consider a fault at  $F$  on line  $GH$  where  $x$  is the per-unit distance of the fault from  $G$ .

An earth fault distance relay at  $G$  having zero sequence compensation will measure voltage  $V_G$  and current  $I_G$  given by:

$$V_G = xZ_{L1} \left\{ I_{G1} + I_{G2} + I_{G0} \cdot \frac{Z_{L0}}{Z_{L1}} + I_{J0} \cdot \frac{Z_{0M}}{Z_{L1}} \right\}$$

$$I_G = I_{G1} + I_{G2} + I_{G0} \cdot \frac{Z_{L0}}{Z_{L1}}$$

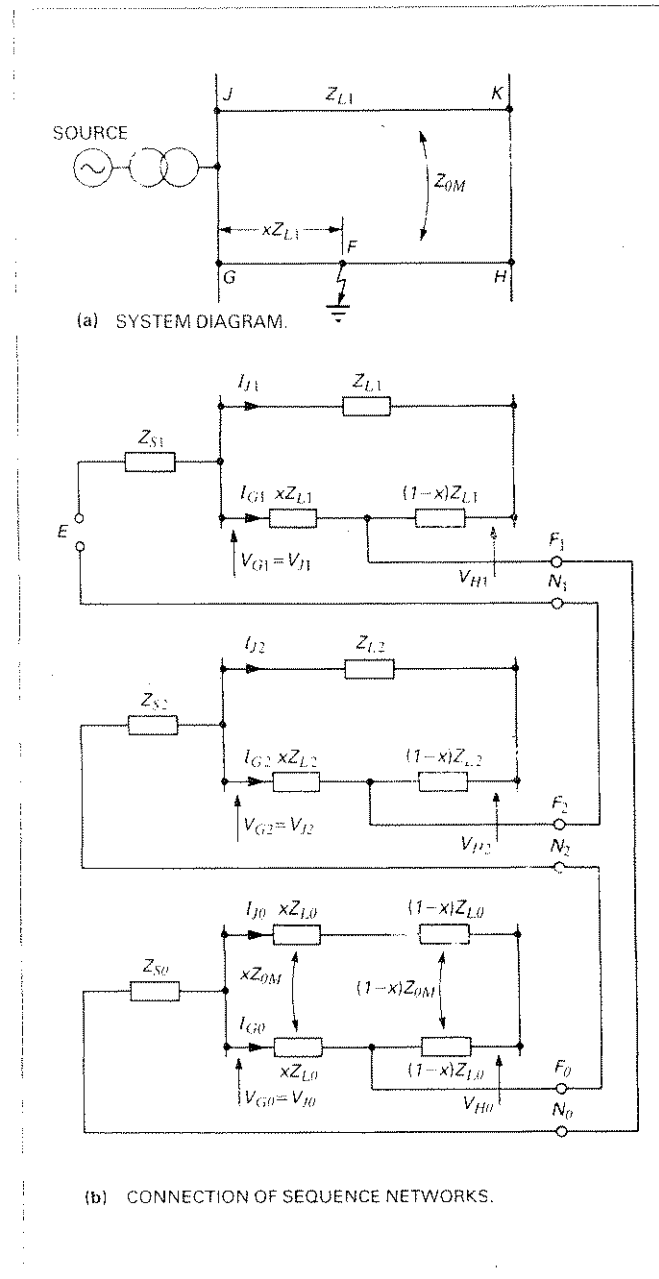


Figure 11.32 Analysis of earth fault on parallel circuits.

Measured impedance  $Z_G$  is given by:

$$\begin{aligned} Z_G &= xZ_{L1} \left\{ 1 + \frac{I_{J0}}{I_{G0}} \cdot \frac{Z_{0M}}{2Z_{L1} + Z_{L0}} \right\} \\ &= xZ_{L1} \left\{ 1 + \frac{x}{2-x} \cdot \frac{Z_{0M}}{2Z_{L1} + Z_{L0}} \right\} \\ &= xZ_{L1} (1 + \rho) \end{aligned}$$

...Equation 11.26

Therefore the relay at  $G$  will under-reach by  $\frac{\rho}{1+\rho} \cdot 100\%$ .

For correct measurement, the relay current  $I_G$  must be increased by  $I_{J0} \cdot \frac{Z_{0M}}{Z_{L1}}$ . This is achieved by taking an input to the relay from the residual circuit of the current transformers in the parallel line. The required mutual compensation is given by  $\frac{Z_{0M}}{3Z_{L1}} \cdot I_{JM}$  where  $I_{JM} = 3I_{J0}$  is the residual current

at  $J$ . Alternatively a mutual replica impedance  $Z_M = \frac{Z_{0M}}{3}$  supplied with the residual current  $I_{JM}$  can be used.

It can be shown that the relay at  $H$  will over-reach for a fault at  $F$  unless mutual compensation is applied. However, the over-reaching effect will extend protection coverage at  $H$  without causing the relay at  $H$  to operate for faults beyond  $G$ . Although mutual compensation may be applied at  $H$ , it does not improve the protection.

Use of conventional mutual compensation suffers from the problem that it can cause the relay on an unfaulted line to operate for a close-up fault on the parallel line. This can be overcome by limiting the amount of mutual compensation used, typically to 1.5 times the level of normal zero sequence compensation. Figures 11.33(a) and 11.33(b)

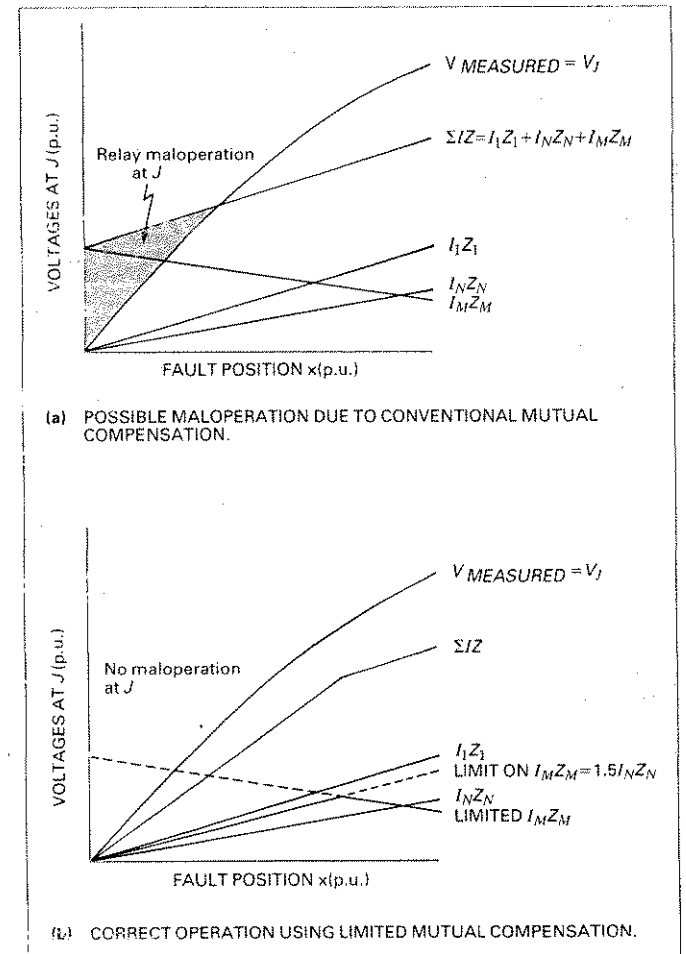


Figure 11.33 Effect of mutual compensation on distance relays for a fault on the parallel circuit.

provide a comparison between the two methods of compensation for a typical 400 kV double circuit line where  $I_M$  is the residual current from the parallel line and  $Z_M$  is the mutual replica impedance.

Figure 11.33(a) shows the case of conventional mutual compensation from which it can be seen that the relay at  $J$  will operate for faults on line  $GH$  when the voltage measured is less than  $\Sigma IZ$ . This incorrect operation is eliminated by limiting the mutual compensation  $I_M Z_M$  to  $1 \cdot 5 I_N Z_N$  as shown on Figure 11.33(b).

It can be shown that the limitation of  $I_M \cdot Z_M$  will not effect the correct measurement of relays on a faulty line, for example, relays at  $G$  and  $H$  on line  $GH$ .

### 11.30

#### POWER SWING BLOCKING

Power swings are variations in power flow which occur when the voltage of generators at different points of the power system slip relative to each other to cater for changes of load magnitude and direction or as a result of faults and their subsequent clearance.

The result of a power swing may cause the impedance presented to a distance relay to move away from the normal load area and into the relay characteristic. In the case of a transient power swing it is important that the distance relay should not trip and should allow the power system to return to a stable condition. For this reason, most distance protection schemes applied to transmission systems, such as 'Micromho' and 'Quadramho', have an optional power swing blocking facility available.

The principle of power swing blocking is illustrated in Figure 11.34. A power swing will normally start from load and can be regarded as a balanced three phase condition. It can be simulated by considering the relative rotation of the generated voltages  $E_G$  and  $E_H$  at each end of the power system. A distance relay located at  $G$  will measure an impedance  $Z_R = V_G/I$  which will vary in magnitude and angle depending on the ratio of  $\frac{E_G}{E_H}$  and the angle of displacement  $\theta$ .

The locus of this impedance as  $E_H$  rotates relative to  $E_G$  represents the power swing. It can be shown that the impedance locus may be represented by a series of circular loci with centres on the extension of the total system impedance  $Z_T$ .

The general expression for  $Z_R$  is given by:

$$Z_R = (Z_{SG} + Z_L + Z_{SH}) \cdot n \frac{(n - \cos \theta) - j \sin \theta}{(n - \cos \theta)^2 + \sin^2 \theta} - Z_{SG}$$

$$= Z_T \cdot \frac{n(n - \cos \theta) - j \sin \theta}{(n - \cos \theta)^2 + \sin^2 \theta} - Z_{SG} \quad \dots \text{Equation 11.27}$$

where  $Z_T = Z_{SG} + Z_L + Z_{SH}$

$$n = \frac{E_G}{E_H}$$

The angle  $\theta$  subtended on the locus from the outer points of the total system impedance  $G'$  and  $H'$  represents the angle between source e.m.f.s  $E_G$  and  $E_H$ .

When  $E_G = E_H$ , the locus of the power swing becomes a straight line bisecting the total system impedance.

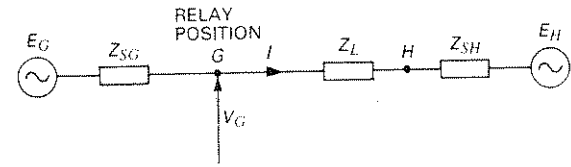
When  $E_G > E_H$ :

Centre of circle will be displaced by  $\frac{Z_T}{n^2 - 1}$  from  $H'$

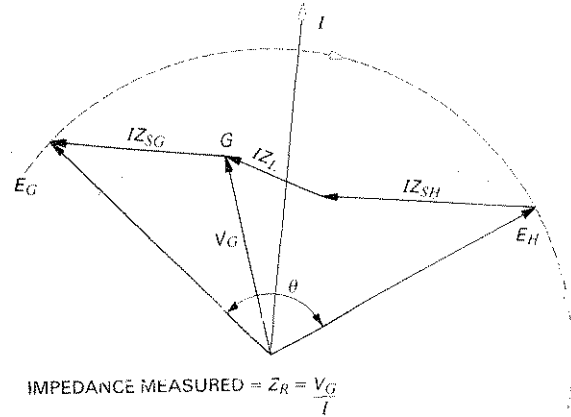
$$\text{Radius of circle} = \frac{n Z_T}{n^2 - 1}$$

When  $E_G < E_H$ :

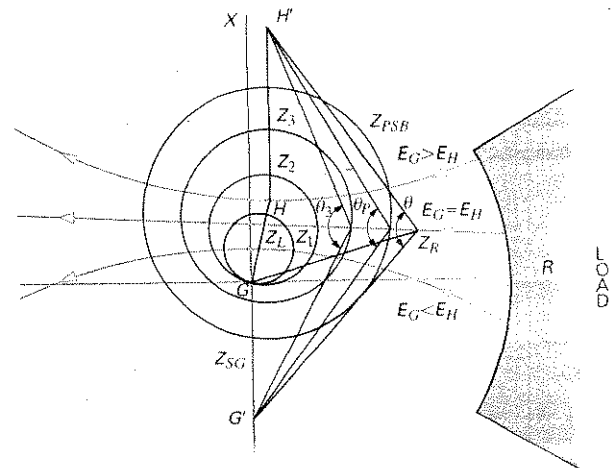
Centre of circle will be displaced by  $\frac{n^2 Z_T}{1 - n^2}$  from  $G'$



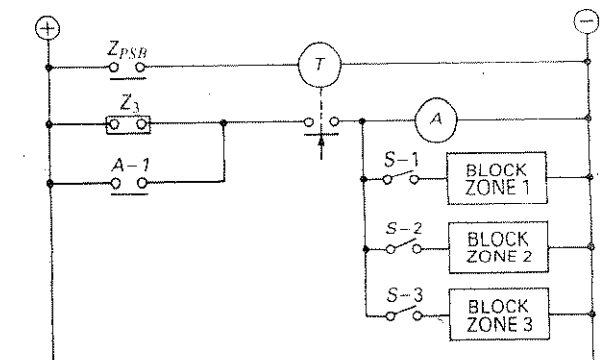
(a) CIRCUIT REPRESENTATION.



(b) VECTOR DIAGRAM.



(c) IMPEDANCE DIAGRAM.



$Z_{PSB}$  = Power swing blocking relay characteristic  
 $Z_3$  = Zone 3 relay characteristic.  
 $T$  = Timer with setting less than time for fastest power swing to travel from  $Z_{PSB}$  to  $Z_3$  that is, from  $\theta_P$  to  $\theta_3$  with  $E_G = E_H$ .  
 $A$  = Auxiliary  
 $S-1, 2, 3$  = Selector switches.

(d) LOGIC DIAGRAM.

Figure 11.34 Principle of power swing blocking.

$$\text{Radius of circle} = \frac{nZ_T}{1-n^2}$$

Detection of a power swing is normally achieved by monitoring the speed of the impedance locus as it approaches the outermost distance protection characteristic.

Figures 11.34(c) and (d) show one method used.

A power swing is a balanced three phase condition and can therefore be detected on a single phase basis. In the example shown, an additional single phase offset mho characteristic  $Z_{PSB}$  is provided, phase-phase connected, to surround the outermost distance relay characteristic  $Z_3$ .

The time taken for the power swing to pass between the characteristics is measured. If this is longer than the time setting of timer  $T$ , then a power swing has occurred and tripping is blocked. If the time is less than the setting, then a fault condition has occurred and normal tripping is allowed.

In order to cater for the fastest power swings,  $Z_{PSB}$  is normally set with as large a reach as possible consistent with load discrimination. When circular distance relay characteristics such as mho or offset mho types are used, the power swing blocking characteristic should have a diameter of at least 1.3 times the diameter of the outermost distance relay characteristic.

The setting of timer  $T$  should be less than the fastest time for a power swing to pass between the two characteristics, that is, from  $\theta_p$  to  $\theta_3$  if  $E_G = E_H$ .

Power swing blocking is normally inhibited when residual current is detected. This ensures that the protection will trip if an earth fault develops during a power swing or if a power swing develops during the dead time of a single phase auto-reclose cycle.

On power systems where generation and equivalent source impedances can be regarded as constant, the locus of a power swing can be predicted with reasonable accuracy. Under these conditions, if power swing tripping is required, the zones of protection for which power swing blocking is effective can be selected to allow tripping at the most suitable relay position.

However, if tripping in Zone 2 or Zone 3 is required, this will depend on the power swing locus remaining within the appropriate characteristic for the Zone 2 or Zone 3 time delay. If this cannot be guaranteed then separate power swing tripping relays should be used.

### 11.31

#### Protection of distance relays from power swing

The a.c. voltage connections and circuits of distance relays are normally protected by fuses or sensitive miniature circuit breakers connected between the voltage transformer secondary windings and the relay terminals.

Distance relays having self-polarized offset characteristics encompassing the zero impedance point of the  $R/X$  diagram and those having sound phase or memory polarization have a tendency to operate on current alone when one or more voltage inputs are removed by the action of fuses or miniature circuit breakers.

Voltage supervision relays or facilities can be incorporated in distance protection schemes to inhibit operation of the distance protection comparators and/or give an alarm when fuses become open circuited. In practice the most common causes of an open circuited fuse are deterioration, accidental removal or failure to replace fuses after maintenance. Fuses will also blow due to faults on the secondary wiring. Various techniques may be used to detect an open circuited fuse.

One method used involves the measurement of voltage across each fuse. Under healthy conditions the measuring circuits of the voltage supervision relay are short circuited

by the fuse and cannot be energized. When one or more fuses are removed or blown, the distance protection burden will produce a voltage across the input circuits of the supervision relay causing it to operate. When applying relays operating on this principle, care should be taken that the ohmic impedance of the distance protection is sufficiently low to cause operation of the supervision relay when a fuse blows.

It should also be noted that this type of relay will commence its operation for a wiring fault only when the appropriate fuses have blown.

In order to achieve faster operating times for wiring faults and blown fuses, modern static distance protection schemes employ voltage supervision which operates from sequence voltages and currents. Zero or negative sequence voltage and corresponding zero or negative sequence current are measured at the distance relay terminals. Discrimination between primary power system faults and wiring faults or loss of fuses is obtained by blocking the distance protection only when zero or negative sequence voltage is detected without the presence of zero or negative sequence current. This arrangement will not detect the loss of all three fuses and where this is required an additional voltage measurement across one fuse similar to the first method described can sometimes be provided.

When miniature circuit breakers are used to protect the VT secondary circuits, contacts from these may be used to inhibit operation of the distance protection comparators and prevent tripping.

### 11.32

#### APPLICATION EXAMPLE OF DISTANCE RELAYS APPLIED TO A 132 kV TRANSMISSION SYSTEM

The system diagram shown in Figure 11.35 indicates a simple 132 kV network supplied from a 275 kV grid through two auto-transformers. The following example shows the calculations necessary to check the suitability of three zone distance protection to the two parallel feeders interconnecting substations  $P$  and  $Q$ , line  $G$  being selected for this purpose. All relevant data for this exercise are given in the diagram.

#### 11.32.1

##### Choice of scheme

Electromechanical and early static designs of switched distance relays were considerably more economical than equivalent designs of full distance protection. The use of the latest solid state components and designs has narrowed this gap so that full distance protection schemes are now specified for many applications. The type 'Quadramho' relay which is a full three zone distance scheme can be applied for the line under consideration.

#### 11.32.2

##### Choice of characteristics

A relay with partially cross-polarized 'mho' characteristics is suitable for protecting most lines, in particular where line length and source impedances are such that the resulting shaped Zone 1 characteristics provide the required coverage of fault resistance.

For very short lines where distance relay reach settings would be low and particularly when there is a low source impedance behind the relay, the shaped 'mho' characteristic may not provide the required ground fault resistive coverage. In such cases, quadrilateral earth fault characteristics with a facility to increase or decrease fault resistance coverage can be applied.

The use of partially cross-polarized 'mho' characteristics for phase and earth faults is considered for this application example.

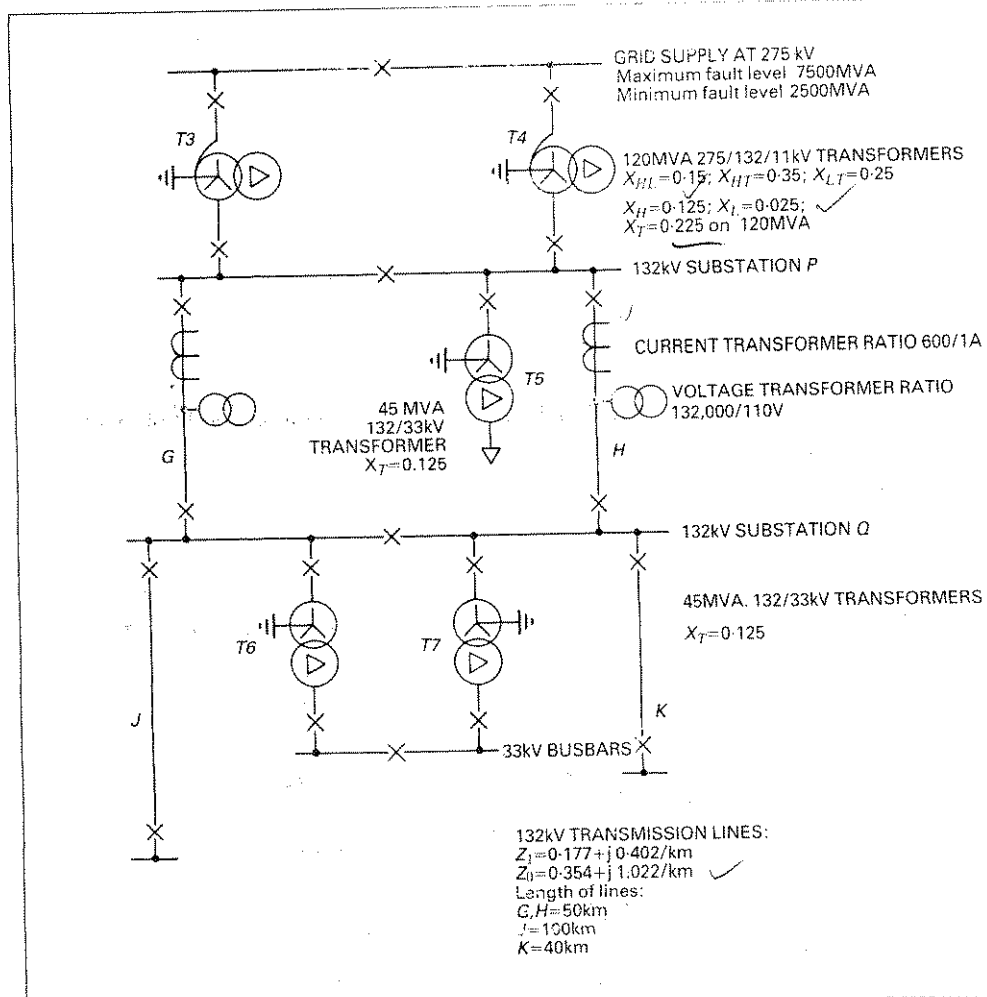


Figure 11.35 Typical 132 kV transmission system.

### 11.32.3 Residual compensation

The system is solidly earthed and the ratio of zero sequence impedance to positive sequence impedance for the protected line is 2.46. When calculating the required relay settings, it is important to bear in mind that the relays are calibrated in terms of positive sequence impedance of the protected line, expressed in secondary ohms. During earth faults, the current in the fault loop is decided not only by the positive sequence impedance but also by the zero sequence impedance of the line. To measure the impedance up to the fault point correctly, a suitable compensation factor known as residual or neutral compensation must be applied. This feature is available in distance relays, either as a scalar or vector quantity.

The residual compensation factor adjustment ( $K_N$ ), available in the distance relay is set equal to

$$\frac{1}{3} \left\{ \frac{Z_0}{Z_1} - 1 \right\}$$

The equivalent neutral replica impedance setting  $Z_N$  is given by

$$Z_N = K_N Z_1$$

For the 132 kV transmission lines:

Positive sequence impedance ( $Z_1$ ) =  $0.177 + j0.402$  ohms primary/km

Zero sequence impedance ( $Z_0$ ) =  $0.354 + j1.022$  ohms primary/km

$$\text{Residual compensation factor } K_N = \frac{1}{3} \left\{ \frac{Z_0}{Z_1} - 1 \right\}$$

$$= \frac{1}{3} \left\{ \frac{0.354 + j1.022}{0.177 + j0.402} - 1 \right\}$$

$$= \frac{1}{3} \left\{ \frac{0.177 + j0.62}{0.177 + j0.402} \right\}$$

$$= 0.49 \angle +7.8^\circ$$

Selected  $K_N = 0.49$

### 11.32.4 Relay characteristic angles

To achieve maximum accuracy and sensitivity, the relay characteristic angles ( $\theta_{PH}$  and  $\theta_N$ ) are set equal to the angles of  $Z_1$  and  $Z_N$  respectively. The required characteristics angle settings are:

$$\theta_{PH} = 66.2^\circ$$

$$\theta_N = 66.2^\circ + 7.8^\circ$$

$$= 74^\circ$$

'Quadramho' has angle settings adjustable from  $45^\circ$  to  $80^\circ$  in  $5^\circ$  steps. When the required value is in between steps, the upper step value is chosen. Therefore relay settings are  $\theta_{PH} = 70^\circ$  and  $\theta_N = 75^\circ$ .

### 11.32.5 Zone 1 reach setting

Zone 1 reach is required to cover 80% of the protected line, to prevent the possibility of relays tripping instantaneously for faults in the next line due to relay errors, voltage and current transformer errors and inaccuracies in line data.

Line impedance

$$Z_{LIG} = 50(0.177 + j0.402) \text{ ohms primary} \\ = 8.85 + j20.1 \text{ ohms primary}$$

$$\begin{aligned}
 \text{Required Zone 1 setting} &= 0.8(8.85 + j20.1) \text{ ohms primary} \\
 \text{Required Zone 1 setting in secondary ohms} &= 0.8(8.85 + j20.1) \frac{600 \times 110}{132,000} \\
 &= 3.54 + j8.04 \text{ ohms} \\
 &= 8.78 / 66.24^\circ
 \end{aligned}$$

### 11.32.6

#### Zone 2 reach setting

The purpose of Zone 2 is to cover the end zone of 20% which is not covered by Zone 1 and to provide time delayed back-up protection for faults on the remote line end busbars. Fast operating contacts of the Zone 2 measuring elements may also be required for use in conjunction with protection signalling equipment to achieve high speed clearance of end zone faults. It is therefore important to ensure that Zone 2 will always reach beyond the far end busbars.

Zone 2 reach is set to cover the protected line plus 50% of the shortest line or 120% of the protected line whichever is the greater. For the application under consideration, Zone 2 is set to cover the protected line plus 50% of the shortest adjacent line.

$$\begin{aligned}
 \text{Required Zone 2 setting} &= Z_{LIG} + 0.5 Z_{LIK} \\
 &= (8.85 + j20.1) + \{0.5 \times 40(0.177 + j0.402)\} \\
 &= 12.39 + j28.14 \text{ ohms primary} \\
 \text{Required Zone 2 setting in secondary ohms} &= (12.39 + j28.14) \frac{600 \times 110}{132,000} \\
 &= 6.20 + j14.07 \\
 &= 15.37 / 66.2^\circ
 \end{aligned}$$

### 11.32.7

#### Effect of parallel lines

When both lines *G* and *H* are in service, under-reach occurs for Zone 2 and Zone 3 faults. The under-reach caused by the infeed from the parallel line can be calculated as follows.

Under-reach =

$$\left( \frac{\text{Impedance of adjacent line included in protected zone}}{\text{Total fault current}} \right) \times \frac{\text{Fault current in parallel line}}{\text{Total fault current}}$$

Percentage under-reach =

$$\frac{\text{Under-reach}}{\text{Protected zone relay reach}} \times 100\%$$

Lines *G* and *H* have the same impedance and current will be shared equally between them. As the Zone 2 setting includes 50% of the impedance of the adjacent section, it follows that with both lines in service the Zone 2 reach is effectively covering only the protected line plus 25% of the adjacent line. This under-reaching effect can only occur for external faults and there is no question of Zone 2 ever failing to reach the end of the protected line because of this, however much infeed is available at the adjacent busbars.

Zone 2 under-reach can be calculated as follows:

$$\begin{aligned}
 \text{Impedance of adjacent line covered by Zone 2 reach} &= \frac{50}{100} (7.08 + j16.08) \\
 &= 8.78 \text{ ohms primary}
 \end{aligned}$$

Zone 2 under-reach

$$\begin{aligned}
 &= 8.78 \times 0.5 \\
 &= 4.39 \text{ ohms primary}
 \end{aligned}$$

Mho relay Zone 2 reach in primary ohms

$$\begin{aligned}
 &= 12.39 + j28.14 \\
 &= 30.74 / 66.2^\circ
 \end{aligned}$$

Zone 2 percentage under-reach

$$\begin{aligned}
 &= \frac{4.39}{30.74} \times 100 \\
 &= 14.28\%
 \end{aligned}$$

### 11.32.8

#### Zone time setting

The Zone 2 time delay should be set to discriminate with the primary protection of the next line sections including circuit breaker trip time. Generally, a Zone 2 time delay setting of 0.2 s–0.3 s is satisfactory but longer times may be required if the Zone 2 reach overlaps slower forms of protection.

### 11.32.9

#### Zone 3 reach setting

The function of Zone 3 is to provide back up protection for uncleared faults in the adjacent line sections. Whenever possible, the Zone 3 reach setting should allow for the under-reaching effect caused by remote infeeds to the fault. Zone 3 reach is usually set to 1.2 times the impedance presented to the relay for a fault at the remote end of the longest adjacent line.

The effect of the parallel line *H* is to cause the Zone 3 unit on line *G* to under-reach so that the impedance of the adjacent line section seen by the relay is doubled for a fault at the end of the adjacent line.

Required Zone 3 setting

$$\begin{aligned}
 &= 1.2\{8.85 + j20.1 + 2(17.7 + j40.2)\} \\
 &= 1.2\{44.25 + j100.5\} \\
 &= 53.1 + j120.6 \\
 &= 131.77 / 66.2^\circ \text{ primary ohms}
 \end{aligned}$$

Required Zone 3 setting in secondary ohms

$$\begin{aligned}
 &= (53.1 + j120.6) \frac{600 \times 110}{132,000} \\
 &= 26.55 + j60.3 \\
 &= 65.89 / 66.2^\circ
 \end{aligned}$$

#### Zone 3 offset

It is usual practice to provide 'offset mho' characteristics for Zone 3, the purpose of the offset or reverse reach being to provide back up protection for the busbars behind the relay. The reverse reach is typically set to 25% of Zone 1 setting.

Zone 1 reach =  $3.54 + j8.04$  ohms secondary

Required Zone 3 reverse reach

$$\begin{aligned}
 &= 0.25(3.54 + j8.04) \text{ ohms secondary} \\
 &= 0.885 + j2.01 \text{ ohms secondary} \\
 &= 2.20 / 66.2^\circ \text{ ohms secondary}
 \end{aligned}$$

### 11.32.10

#### Zone 3 time setting

Before selecting the time settings for Zone 3 operation, it is necessary to check the reach of Zone 3 through the stepdown transformers at substation *Q*. If possible, discriminative tripping should be arranged between the



protection schemes on both sides of the transformers.

Zone 3 will over-reach furthest into the 33 kV system when both 45 MVA transformers are in service and fed by the protected line G only, since if both parallel lines were in service, the distance protection would under-reach.

Impedance of 45 MVA transformer on 132 kV base

$$= j0.125 \times \frac{132^2}{45}$$

$$= j48.4 \text{ ohms primary}$$

Impedance from relaying point to fault on 33 kV busbars

$$= (8.85 + j20.1) + j \frac{48.4}{2}$$

$$= 8.85 + j44.3$$

$$= 45.18 \angle 78.7^\circ \text{ ohms primary}$$

$$= 22.59 \angle 78.7^\circ \text{ ohms secondary}$$

Zone 3 reach setting (forward)

$$= 65.89 \angle 66.2^\circ \text{ ohms secondary}$$

For a three phase fault, the reach of Zone 3 into the 33 kV system is approximately  $(65.89 - 22.59) = 43.3$  ohms. It is important to note that this impedance is in secondary ohms to a 132 kV base. The equivalent impedance in primary ohms to a 33 kV base is

$$43.3 \times \frac{132,000}{600 \times 110} \times \frac{33^2}{132^2} = 5.41 \text{ ohms}$$

The time setting for Zone 3 must be adjusted to discriminate with any 33 kV protection which it will overlap.

If the reach into the 33 kV system is unacceptable, the Zone 3 reach setting can be permanently reduced in which case it may not provide complete back up protection for the faults in the adjacent feeders when both lines are in service.

Alternatively the Zone 3 reach could be reduced to  $1.2 \times$  (Impedance of the protected line + impedance of the longest adjacent feeder) whenever one of the parallel lines is taken out of service.

### 11.32.11

#### Check of minimum voltage at relay for faults at Zone 1 reach

It is usual for distance relay manufacturers to declare the minimum voltage at which the relay will maintain its accuracy in terms of secondary voltage for faults at the Zone 1 reach point. This may be alternatively expressed in terms of source to setting ratio  $Z_S/Z_L$  (otherwise known as  $S/R$ ) up to which the relay may be applied. For phase faults, the minimum voltage is given in terms of secondary phase to phase volts, and for earth faults in terms of phase to neutral volts.

The minimum voltage at the relaying point will occur when both lines G and H are in service fed from one transformer at bus P and with minimum fault MVA on the 275 kV busbars.

#### a. Phase faults

Figure 11.36(a) shows the positive sequence network which is used to analyse a three phase fault at the Zone 1 reach point of the distance relays protecting line G. The resistive component of line impedance has been ignored, which is a reasonable approximation for this analysis. R<sub>1</sub> indicates the relay position.

The relevant impedances are obtained as follows:

Source impedance

$$Z_{S1} = j \frac{275^2}{2500} = j30.25 \text{ ohms on 275 kV base.}$$

$$= j30.25 \times \frac{132^2}{275^2} = j6.97 \text{ ohms on 132 kV base}$$

Transformer T3

$$Z_{T13} = j0.15 \times \frac{132^2}{120} = j21.78 \text{ ohms primary}$$

Parallel lines G and H

Effective impedance for three phase fault at the Zone 1 reach point is given by

$$\frac{0.8Z_{LAG} \times (Z_{L1H} + 0.2Z_{L1G})}{0.8Z_{LAG} + Z_{L1H} + 0.2Z_{L1G}}$$

$$= \frac{j16.08 \times j24.12}{j16.08 + j24.12}$$

$$= j9.65 \text{ ohms primary}$$

Total positive sequence impedance to fault, ( $Z_{F1}$ ), is given by

$$Z_{F1} = j6.97 + j21.78 + j9.65$$

$$= j38.4 \text{ ohms primary}$$

Fault current for a three phase fault at the Zone 1 reach point

$$= I_1 = \frac{132,000}{\sqrt{3} \times 38.4}$$

$$= 1985 \text{ A}$$

The secondary phase to phase voltage seen by the relays at substation P

$$= \sqrt{3} \times 1985 \times 9.65 \times \frac{110}{132,000}$$

$$= 27.65 \text{ volts secondary}$$

#### b. Earth faults

When calculating the minimum relay voltage for an earth fault at the reach point, account must be taken of any earthed star/delta transformers on the system. These will effect the distribution of zero sequence current and depending on their position may increase or reduce the voltage measured by the relay.

For the example considered, the minimum voltage occurs when both 45 MVA transformers T6 and T7 in front of the relay are in service and transformer T5 behind the relay is disconnected.

Figure 11.36 shows the resulting positive, negative and zero sequence networks for a phase to earth fault at the Zone 1 reach point of the distance relay protecting line G at substation Q.

Total positive sequence impedance

$$Z_{F1} = j38.4 \text{ ohms primary}$$

Total negative sequence impedance

$$Z_{F2} = j38.4 \text{ ohms primary}$$

Zero sequence impedance values are obtained as follows:

Source impedance

For this application  $Z_{S0}$  is assumed equal to  $Z_{S1}$

Auto-transformer T3

Equivalent star impedances are

$$Z_{T3T} \text{ (tertiary)} = j0.225 \times \frac{132^2}{120} = j32.67 \text{ ohms primary}$$

$$Z_{T3H} \text{ (275 kV)} = j0.125 \times \frac{132^2}{120} = j18.15 \text{ ohms primary}$$

$$Z_{T3L} \text{ (132 kV)} = j0.025 \times \frac{132^2}{120} = j3.63 \text{ ohms primary}$$

Parallel lines G and H

Zero sequence impedance of each line

$$= Z_{L0G} = Z_{L0H}$$

$$= 50 \times j1.022 = j51.1 \text{ ohms primary}$$



Sequence currents at the fault point are given by

$$I_1 = I_2 = I_0 = \frac{132,000}{\sqrt{3} (j119.16)} = 639.6 \text{ A primary}$$

Sequence currents at the relaying point  $R$  are given by

$$I_{R1} = 0.6 I_1$$

$$I_{R2} = 0.6 I_2$$

$$I_{R0} = 0.6 I_0$$

Current at relaying point

$$= I_{R1} + I_{R2} + I_{R0}$$

$$= 0.6 \times 3 \times 639.6$$

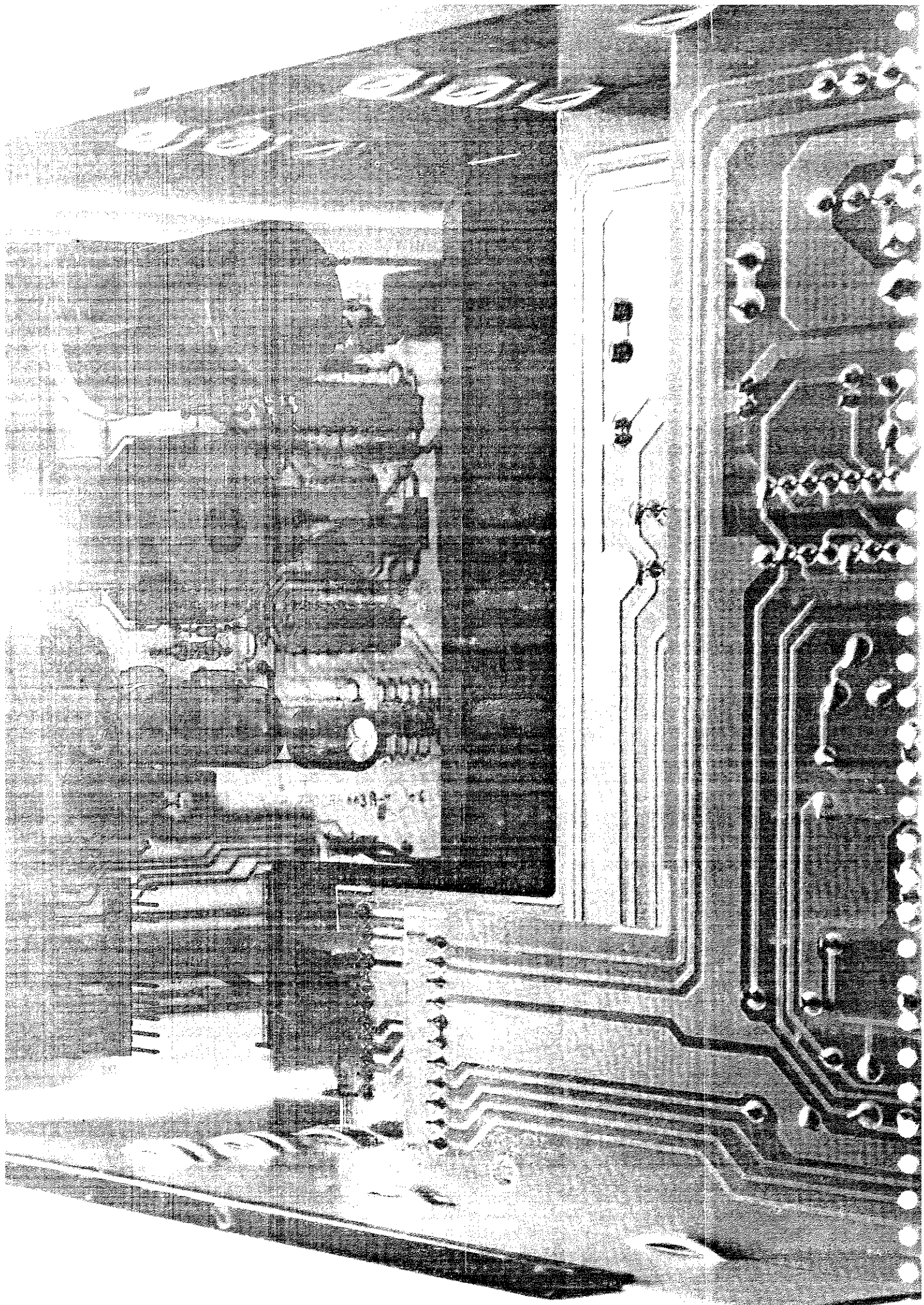
$$= 1151 \text{ A primary}$$

Secondary current at relaying point

$$= 1151 \times \frac{1}{600}$$

$$= 1.92 \text{ A.}$$

11



# Distance protection schemes

12.1

12.2

12.3

12.4

12.5

12.6

12.7

12.8

12.9

## 12.1

One of the main disadvantages of conventional time-stepped distance protection, as illustrated in Figure 12.1, is the fact that the instantaneous Zone 1 of the protection at each end of the protected line cannot be set to cover the whole of the feeder length and is usually set to about 80%. This leaves two 'end zones', each being about 20% of the protected feeder length, in which faults are cleared instantaneously (Zone 1 time) by the protection at one end of the feeder but in Zone 2 time (0.3 to 0.4 seconds typically) by the protection at the other end of the feeder.

In some applications this situation cannot be tolerated, for two main reasons:

- a. Faults remaining on the feeder for Zone 2 time may cause the system to become unstable.
- b. Where high speed auto-reclosing is used, the non-simultaneous opening of the circuit breakers at both ends of the faulted section results in no 'dead time' during the auto-reclose cycle for the fault to be extinguished and for ionized gases to clear. This results in the possibility that a transient fault will cause permanent lockout of the circuit breakers at each end of the line section.

Unit schemes of protection which compare the conditions at the two ends of the protected feeder simultaneously can positively identify whether the fault is internal or external to the protected section, and are capable of providing high speed protection for the whole feeder length. This advantage is balanced by the fact that the unit scheme does not provide the back up protection to adjacent feeders given by a distance scheme.

The most desirable scheme is obviously one which combines the best features of both arrangements, that is, instantaneous tripping over the whole feeder length plus back-up protection to adjacent feeders. This can be achieved by interconnecting the distance protections at each end of the protected feeder by a signalling channel. The signalling channel may be high frequency (hf) operating over the overhead line conductors, voice frequency (vf) using either pilots or a power line carrier communications channel, a radio link, microwave channel or a fibre optic link. These communication techniques are described in detail in Chapter 8.

The purpose of the signalling channel is to transmit information about the system conditions from one end of the protected line to the other; it can also be arranged to initiate

or prevent tripping of the remote circuit breaker. The former arrangement is generally referred to as a 'transfer trip scheme' while the latter is known as a 'blocking scheme'. When carrier or signalling equipment is not available, fast tripping for all line faults can be achieved by extending the Zone 1 reach of distance relays under control of an associated auto-reclose scheme. The resulting distance scheme is referred to as a 'Zone 1 Extension Scheme' and its application is normally limited to distribution systems or to interconnected power systems when carrier is temporarily taken out of service.

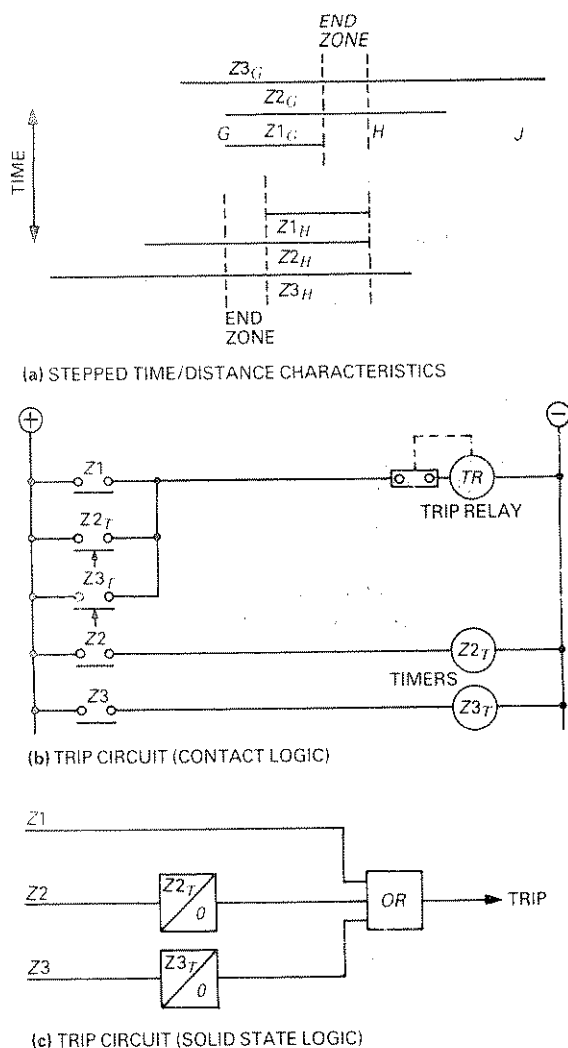
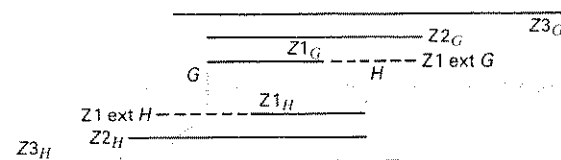


Figure 12.1 Conventional distance scheme.

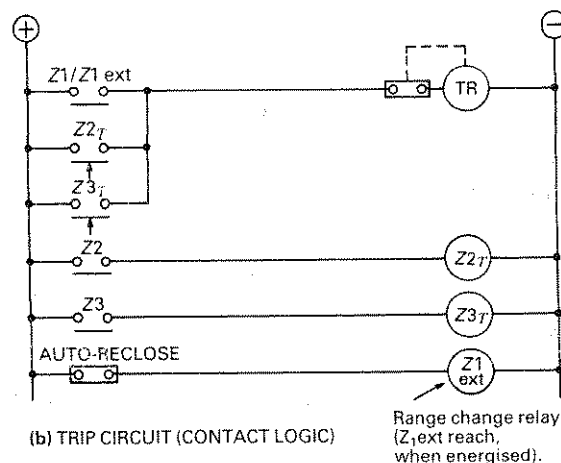
## 12.2

The scheme is intended for use with an auto-reclose relay. The Zone 1 units of the distance relay have two setting controls; one, as in the basic distance scheme, is set to cover 80% of the protected line length and the other, known as 'Extended Zone1', is set to cover 120% of the protected line. The Zone 1 reach is normally controlled by the extended Zone 1 setting and is reset to the basic value when a command from the auto-reclose relay is received.

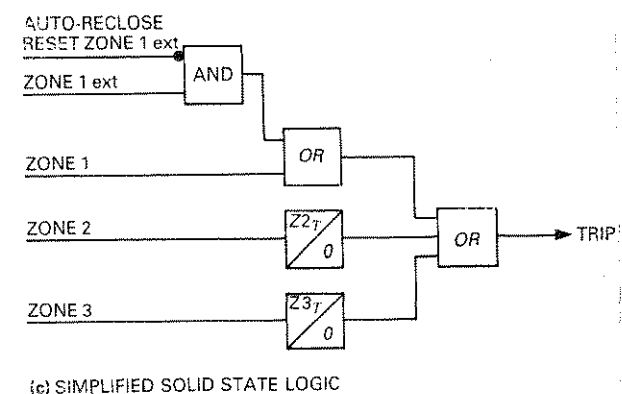
On occurrence of a fault at any point within the extended Zone 1 reach, the relay operates in Zone 1 time, trips the circuit breaker and initiates auto-reclosure. A contact from the auto-reclose relay is used to reset the Zone 1 reach of the distance relay to the basic value of 80%. The auto-reclose contact used for this purpose operates before the closing pulse is applied to the breaker and resets only at the



(a) DISTANCE/TIME CHARACTERISTICS



(b) TRIP CIRCUIT (CONTACT LOGIC)



(c) SIMPLIFIED SOLID STATE LOGIC

Figure 12.2 Zone 1 extension scheme.

end of the reclaim time. The contact should also operate when the auto-reclose facility is out of service.

If the fault is transient, the tripped circuit breakers will reclose successfully but, if permanent, further tripping during the reclaim time is subject to the discrimination obtained with normal Zone 1 and Zone 2 settings. The scheme is shown in Figure 12.2.

The disadvantage of the Zone 1 extension scheme is that external faults, between the far end of the line and the first 20% of the next line, result in the tripping of the circuit breakers external to the faulted section, increasing the amount of breaker maintenance needed. This is illustrated in Figure 12.3 (a) for a single circuit line where three circuit breakers operate and in Figure 12.3 (b) for a double circuit line, where five circuit breakers operate.

Since the use of signalling equipment is not necessary, this scheme is often used as a temporary replacement for carrier aided schemes when the signalling equipment is out of service.



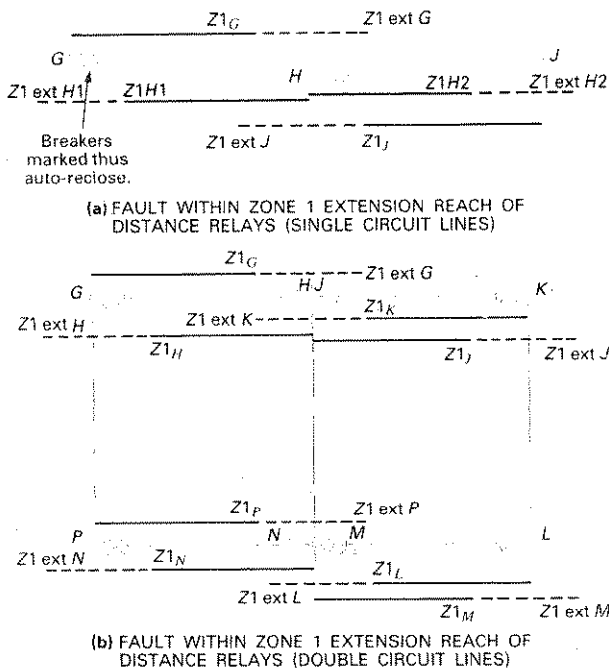


Figure 12.3 Performance of distance relays fitted with Zone 1 extension when used with auto-reclose relays on single and double circuit lines.

## 12.3

### 12.3.1

#### Direct transfer trip (under-reaching) scheme

The simplest way of speeding up fault clearance at the terminal which clears an end zone fault in Zone 2 time is to adopt a direct transfer trip or intertrip technique as shown in Figure 12.4. A Zone 1 contact is arranged to send a signal to the remote end and a receive relay contact at that end is connected in the tripping circuit. The scheme in which the Zone 1 relay is used to send a signal to the remote end of the feeder in this manner is termed a 'transfer trip under-reaching scheme'.

Considering now a fault  $F$  in the end zone at end  $H$  in Figure 12.1(a), operation of the Zone 1 relay at end  $H$  initiates carrier transmission as well as tripping at that end. The receipt of a signal at end  $G$  initiates tripping immediately because the receive relay contact is connected directly to the trip relay. The disadvantage of this scheme is the possibility of undesired tripping by accidental operation or maloperation of signalling equipment.

### 12.3.2

#### Permissive under-reach transfer trip scheme

The direct transfer trip scheme is made more secure by supervising the received signal with the instantaneous Zone 2 operation before allowing tripping, as shown in Figure 12.5. The scheme is then known as a 'permissive under-reach transfer trip scheme'.

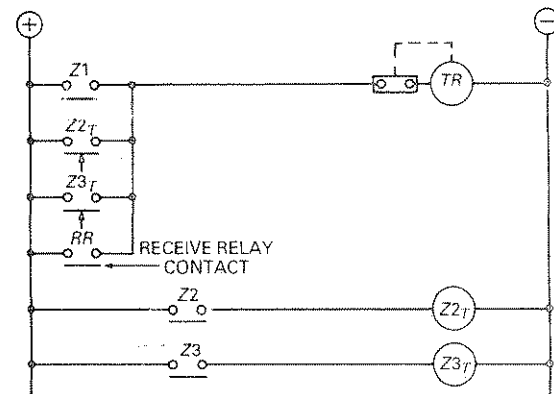
Time delayed resetting of the 'Signal Received' element is required to ensure that the relays at both ends of a single-end fed faulted line of a parallel feeder circuit have time to trip when the fault is close to one end.

The need for the time delayed resetting may be explained by considering a fault ' $F$ ' in a double circuit line as shown

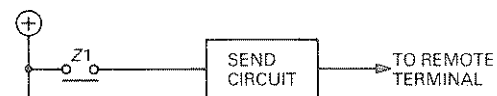
in Figure 12.6. The fault is close to terminal  $G$ , so there is negligible infeed from terminal  $H$  when the fault at  $F$  occurs. The protection at  $H$  detects a Zone 2 fault only after the breaker at  $G$  has tripped. It is possible for the 'signal received' element at  $H$  to reset before the Zone 2 unit at end  $H$  operates. It is therefore necessary to delay the resetting of the 'signal received' element to ensure high speed tripping at end  $H$ .

This scheme requires only a single signalling channel for two way signalling between line ends as the channel is keyed by the under-reaching Zone 1 units.

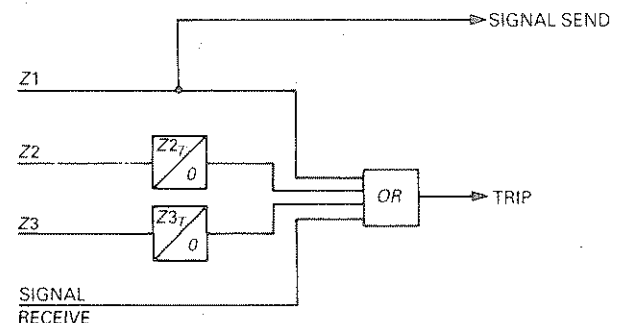
When the circuit breaker at one end is open, instantaneous clearance cannot be achieved for end-zone faults near the 'breaker open' terminal.



(a) TRIP CIRCUIT CONTACT LOGIC



(b) SIGNALLING CHANNEL SEND ARRANGEMENT (CONTACT LOGIC)



(c) SIMPLIFIED SOLID STATE LOGIC.

Figure 12.4 Direct transfer trip (under-reaching) scheme.

### 12.3.3

#### Permissive over-reach transfer tripping scheme

In this scheme a relay set to reach beyond the far end of the protected line is used to send an intertripping signal to the remote end. In this case, however, it is essential that the receive relay contact is monitored by a directional relay contact to ensure that tripping does not take place unless the fault is within the protected section; see Figure 12.7. The instantaneous contacts of the Zone 2 unit are arranged to send the signal, and the received signal, supervised by Zone 2 operation, is used to energize the trip circuit. The

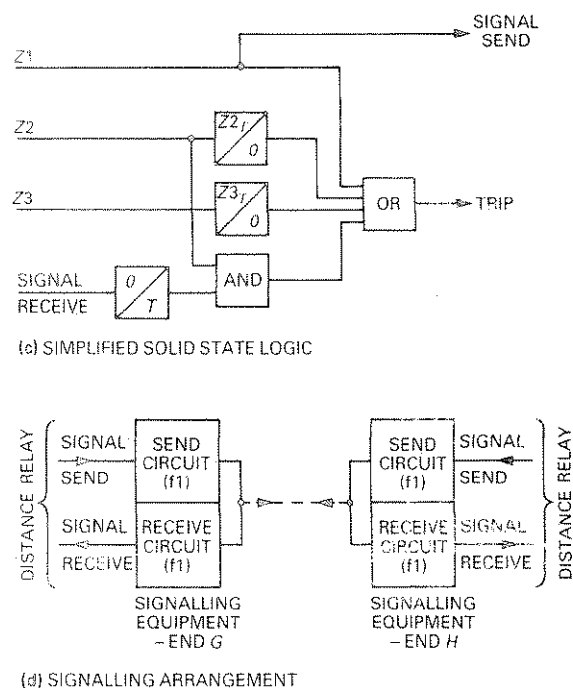
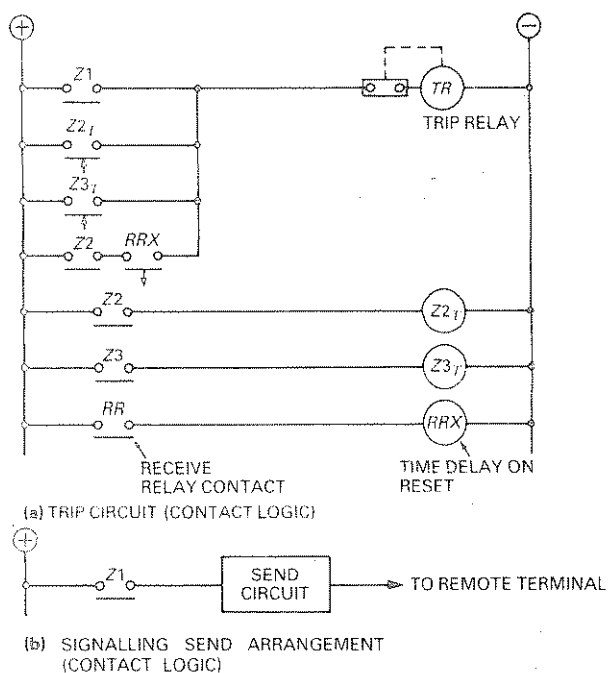


Figure 12.5 Permissive under-reach transfer trip scheme.

scheme is then known as a 'permissive over-reach transfer trip scheme' or 'directional comparison scheme'.

Since the signalling channel is keyed by over-reaching Zone 2 units, the scheme requires duplex signalling channels — one frequency for each direction of signalling.

If distance relays with mho characteristics are used the scheme is better suited than the permissive under-reaching scheme for protecting short lines, because the resistive coverage of the Zone 2 unit is greater than that of Zone 1.

To prevent operation under current reversal conditions, in a parallel feeder circuit, it is necessary to use a time delayed unit in the permissive trip circuit. This current reversal guard is necessary only when the Zone 2 reach is set greater than 150% of the protected line impedance.

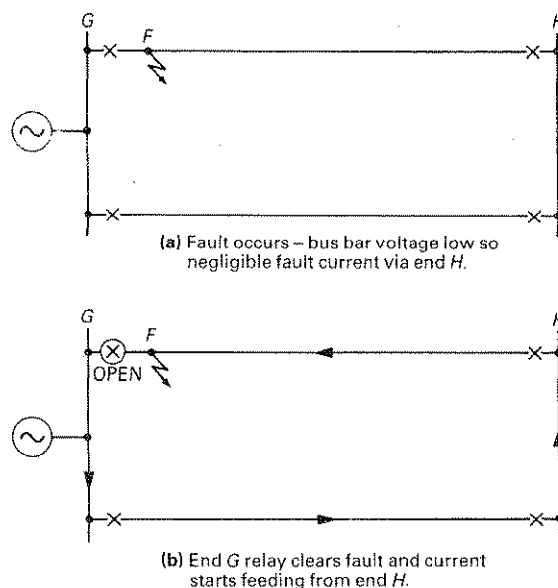


Figure 12.6 Single end fed close-up fault on double circuit line.

The need for such a time delayed unit is best explained by the parallel feeder arrangement shown in Figure 12.8. If a fault occurs near circuit breaker *K* of feeder *JK*, the protection at *K* will clear the fault faster than the protection at *J*. As soon as breaker *K* opens, the direction of current flow down the healthy feeder reverses. The Zone 2 units at end *G*, which operated and sent the signal to end *H* when the fault at *K* started, reset when breaker *K* opens.

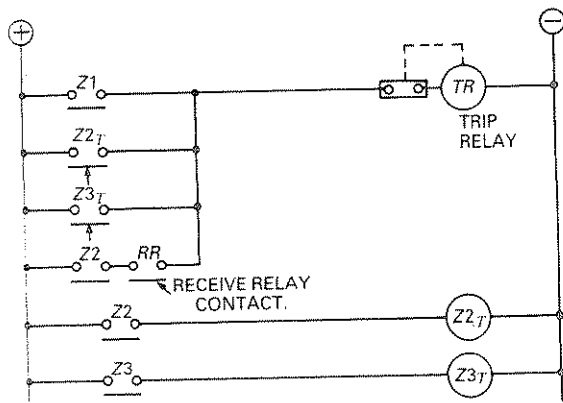
The Zone 2 units at end *H*, which restrained when the fault at *K* started, operate when breaker *K* opens. If the Zone 2 units at end *H* operate before Zone 2 at end *G* resets, tripping of the breakers at *G* and *H* may take place.

To avoid this possible maloperation, a time delayed unit is used to block the permissive trip and signal send circuits as shown in Figure 12.9. The time delayed unit is energized if a signal is received and there is no operation of Zone 2 units. The time delayed unit has an adjustable delay on pick up (*tp*) and is usually set to allow instantaneous tripping to take place for any internal faults, taking into account a possible slower operation of Zone 2. The time delayed unit will have operated and blocked the permissive trip and signal send circuit by the time the current reversal described above takes place.

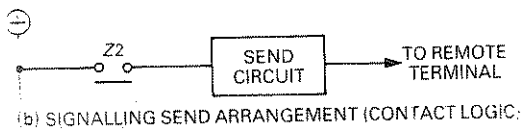
The time delayed unit is de-energized if the Zone 2 units operate or the 'signal received' element resets. The reset time delay (*td*) of the time delay unit is set to cover any overlap in time caused by Zone 2 units operating and the signal resetting at end *H*, when the current in the healthy feeder reverses. Using a time delay unit in this manner, that is with a time delay on pick up and resetting, means that no extra time delay is added in the permissive trip circuit for an internal fault.

In the standard permissive over-reach scheme, as with the permissive under-reach scheme, instantaneous clearance cannot be achieved for end zone faults near the 'breaker open' terminal. However, to achieve fast clearance for these faults, additional circuitry can be included in the scheme to echo the 'received signal' to the remote terminal, as shown in Figure 12.10. An auxiliary contact of the local circuit breaker is connected to the distance protection scheme to show when the circuit breaker is open or closed. When a signal is received and the breaker is in the open position, the received signal is echoed back.

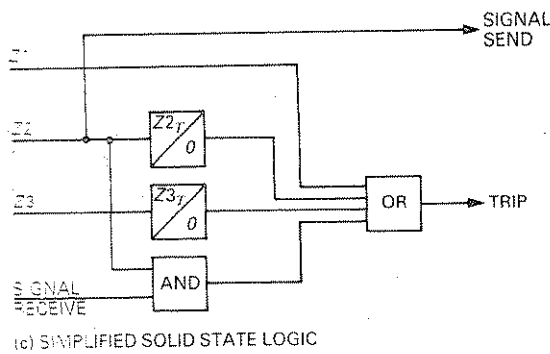




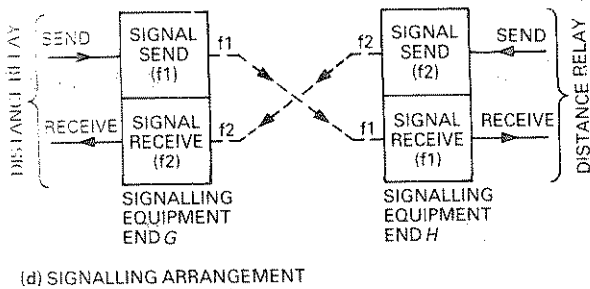
(a) TRIP CIRCUIT (CONTACT LOGIC)



(b) SIGNALLING SEND ARRANGEMENT (CONTACT LOGIC)



(c) SIMPLIFIED SOLID STATE LOGIC



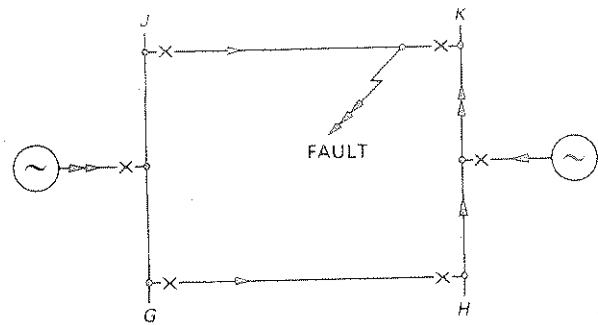
(d) SIGNALLING ARRANGEMENT

Figure 12.7 Permissive over-reach transfer trip scheme.

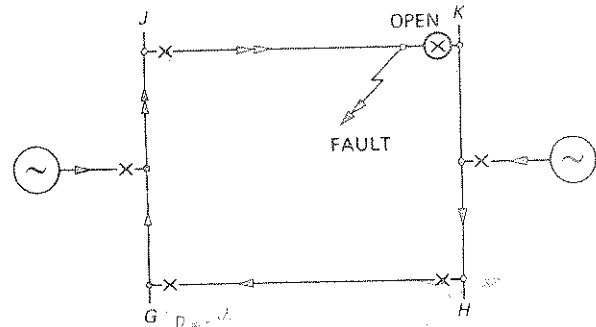
A time delay ( $T1$ ) is required in the echo circuit to prevent tripping of the remote end breaker when the local breaker is tripped by the busbar protection or breaker fail protection associated with other feeders connected to the busbar. The time delay ensures that the remote end Zone 2 unit will reset by the time the echoed signal is received at that end. Signal transmission can take place even after the remote end breaker has tripped, so to avoid continuous transmission due to lock-up of both signals, the time delay circuit ( $T2$ ) is used. After the time delay ( $T2$ ) 'signal send' is blocked.

### 12.3.4 Acceleration scheme

This scheme is similar to the permissive under-reach transfer trip scheme in its principle of operation, but it is



(a) FAULT CURRENT DISTRIBUTION AT INSTANT OF FAULT



(b) FAULT CURRENT DISTRIBUTION WITH CIRCUIT BREAKER K OPEN

Figure 12.8 Current reversal in healthy feeder.

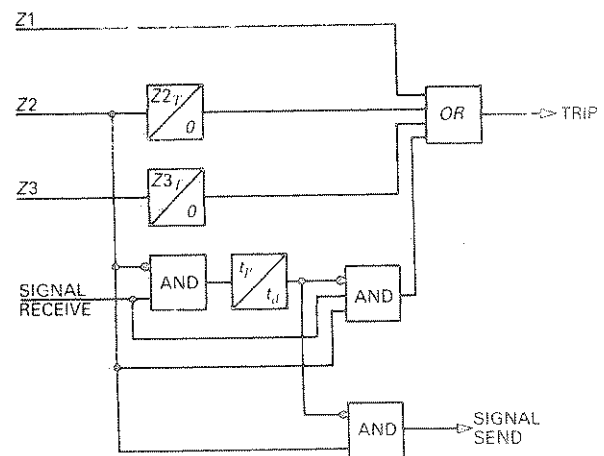


Figure 12.9 Current reversal guard circuit - permissive over-reach scheme (POR).

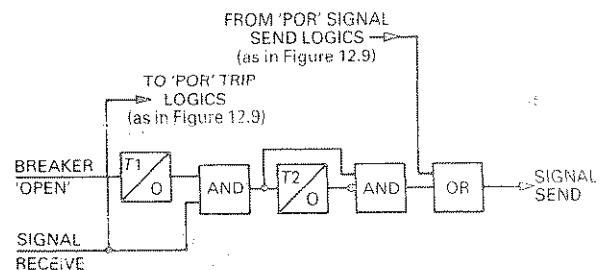


Figure 12.10 'Breaker open' signal echo circuit - permissive over-reach scheme.

applicable only to zone switched distance relays which share the same measuring units for both Zone 1 and Zone 2. In these relays the reach of the measuring units is extended from Zone 1 to Zone 2 by means of a range change relay, after Zone 2 time.

In this scheme, the under-reaching Zone 1 unit is arranged to send a signal to the remote end of the feeder in addition to tripping the local circuit breaker. The receive relay contact is arranged to operate the range change relay which extends the reach of the measuring unit from Zone 1 to Zone 2 immediately instead of at the end of Zone 2 time delay. This accelerates the fault clearance at the remote end. The scheme is shown in Figure 12.11.

The scheme is not quite as fast in operation as the permissive intertrip schemes, since time is required for the distance measuring unit to operate after the reach has been changed from Zone 1 to Zone 2. It may be argued, though, that the slightly slower operation will result in increased security from maloperation.

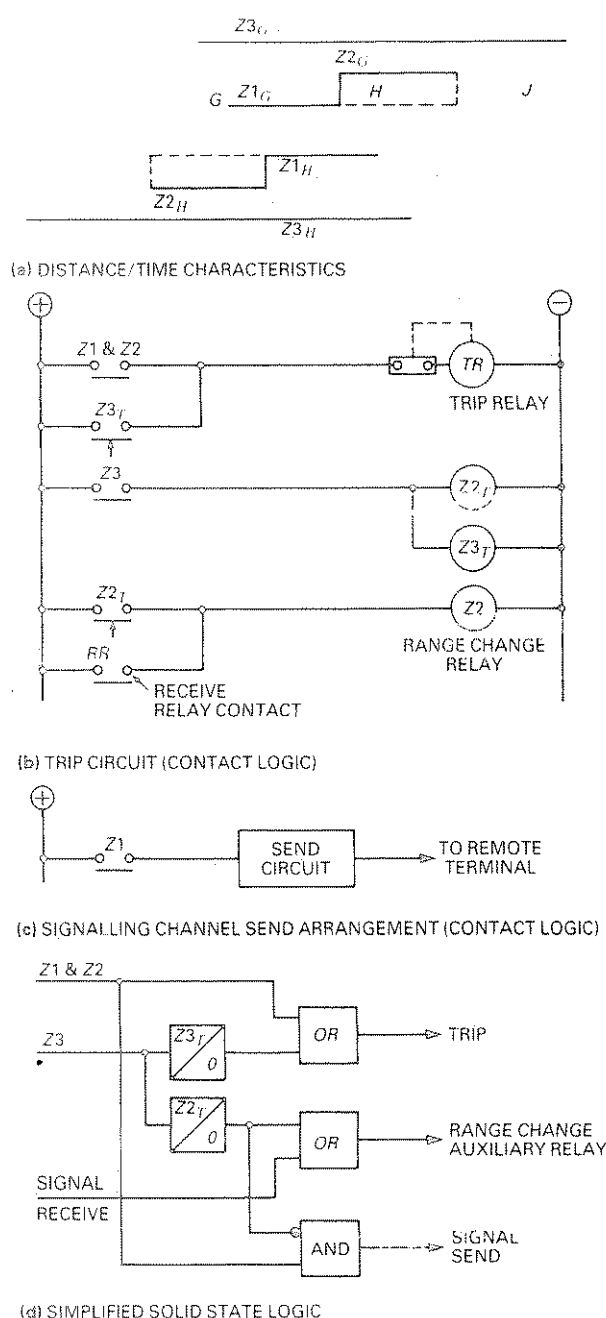


Figure 12.11 Acceleration scheme.

## 12.4

The alternative arrangements so far described have used the signalling channel to transmit a tripping instruction. If the signalling channel fails or there is no infeed from one end, end-of-zone faults will take longer to be cleared.

The blocking scheme uses inverse logic. Signalling is initiated only for external faults and signalling transmission takes place over healthy line sections. Fast fault clearance occurs when no signal is received and the over-reaching distance measuring units (Z2) looking into the line operate. The signalling channel is keyed by reverse looking distance units (Z3). An ideal blocking scheme is shown in Figure 12.12.

The signalling channel used need only be of the single frequency type that operates both local and remote receive relays when a block signal is initiated at any end of the protected section.

A blocking instruction has to be sent by the reverse looking Zone 3 units to prevent instantaneous tripping of the remote relay for Zone 2 faults external to the protected section. To achieve this, the reverse looking Zone 3 units and the signalling channel must operate faster than the forward looking Zone 2 units. In practice this is seldom the case and to ensure discrimination a short time delay is generally introduced into the blocking mode trip circuit, as illustrated in Figure 12.13.

The faults shown at R, S and T in Figure 12.12 are now considered.

A fault at R is seen by the Zone 1 relays at both ends G and end H; as a result, the fault is cleared instantaneously at both ends of the protected line. Signalling is controlled by the Zone 3 units looking away from the protected section, so no transmission takes place thus giving fast back-up tripping via the forward looking Zone 2 units.

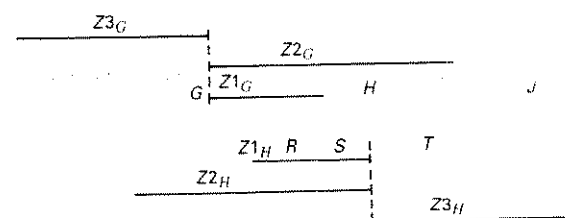
A fault at S is seen by the forward looking Zone 2 units at ends G and H and by the Zone 1 units at end H. No signal transmission takes place, since the fault is internal and the fault is cleared in Zone 1 time at end H and after the short time lag (STL) at end G.

A fault at T is seen by the reverse looking Zone 3 units at end H and the forward looking Zone 2 units at end G. The fault at T would normally be cleared by the Zone 1 units associated with line section HJ. To prevent the Zone 2 units at end G from tripping, the reverse looking Zone 3 units at end H send a blocking signal to end G. If the fault is not cleared instantaneously by the protections on line section HJ, the trip signal will be given at end G after the normal Zone 2 time lapse.

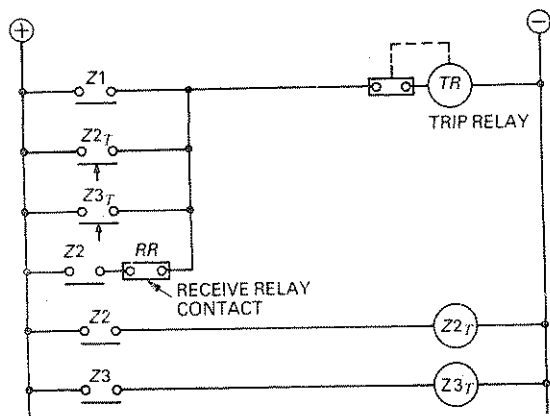
The setting of the reverse looking Zone 3 units must be greater than that of Zone 2 units at the remote end of the feeder, otherwise there is the possibility of Zone 2 units initiating tripping and the reverse looking Zone 3 units failing to see an external fault. This would result in instantaneous tripping for an external fault.

When the signalling channel is used for a stabilizing signal, as in the above case, transmission takes place over a healthy line section. The signalling channel should then be more reliable when used in the blocking mode, especially if the channel is power line carrier. It is essential that the operating times of the various relays be skillfully co-ordinated for all system conditions, so that sufficient time is always allowed for the receipt of a blocking signal from the remote end of the feeder. If this is not done accurately, the scheme may trip for an external fault or alternatively, the end zone tripping times may be delayed further than is necessary.

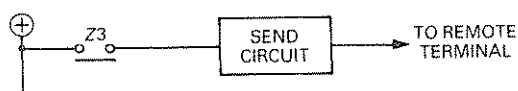
If the signalling channel fails, definite action must be taken to revert the scheme to conventional basic distance protection. Normally, the blocking mode trip circuit is supervised by a 'channel-in-service' contact so that the blocking



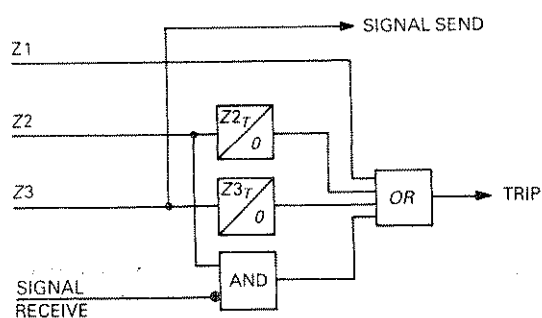
(a) DISTANCE/TIME CHARACTERISTICS



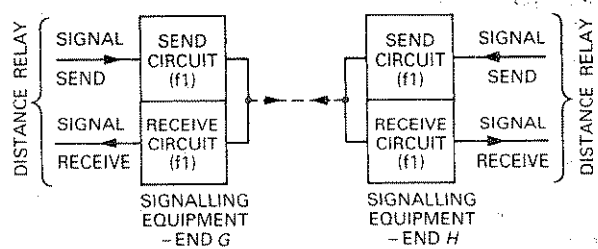
(b) TRIP CIRCUIT (CONTACT LOGIC)



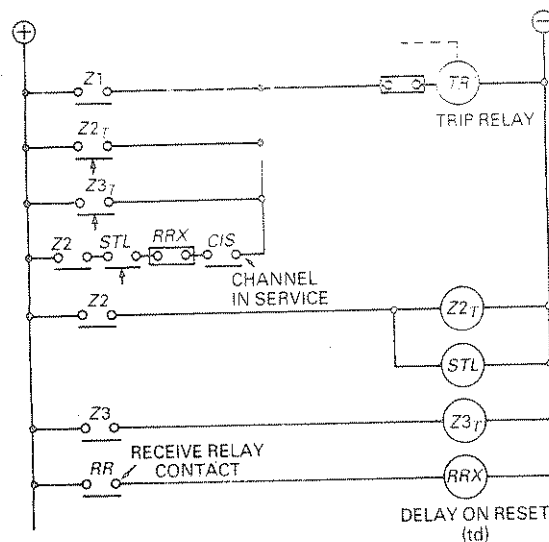
(c) SIGNALLING CHANNEL SEND ARRANGEMENT (CONTACT LOGIC)



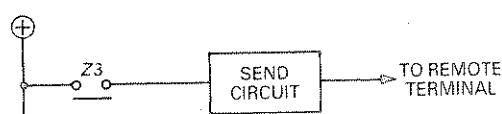
(d) SIMPLIFIED SOLID STATE LOGIC



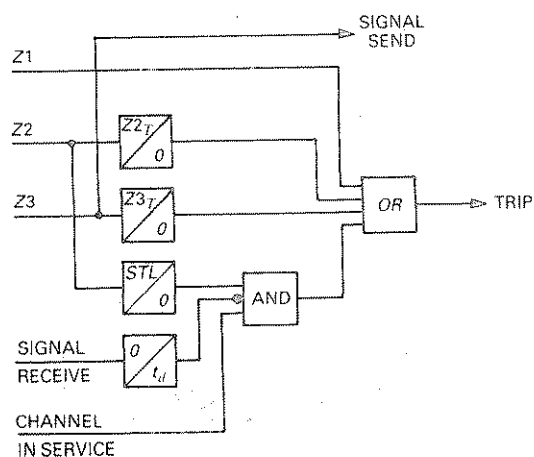
(e) SIGNALLING ARRANGEMENT.



(a) TRIP CIRCUIT (CONTACT LOGIC)



(b) SIGNALLING CHANNEL SEND ARRANGEMENT (CONTACT LOGIC)



(c) SIMPLIFIED SOLID STATE LOGIC

Figure 12.13 Practical blocking scheme.

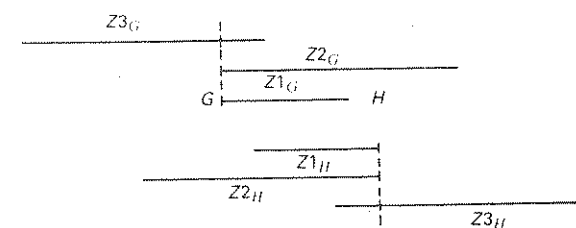
mode trip circuit is isolated when the channel is out of service, as shown in Figure 12.13.

The ideal blocking scheme illustrated in Figure 12.12 shows reverse looking Zone 3 units that initiate the blocking signal. In practice, the Zone 3 units are set with a forward offset characteristic to provide back-up protection for busbar faults after the Zone 3 time delay. This makes it necessary to stop the blocking signal being sent for internal faults. This is achieved by making the signal send circuit conditional upon non-operation of the forward looking Zone 2 units, as shown in Figure 12.14.

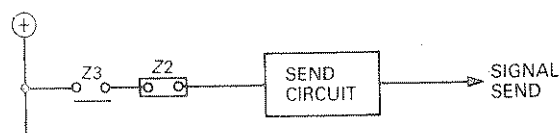
As for the permissive over-reach scheme, the blocking scheme also is affected by the current reversal in the healthy feeder due to a fault in a double circuit line.

If the fault condition shown in Figure 12.8 occurs, the reverse looking Zone 3 units at end *H* will have applied the blocking signal to the protection at end *G* of the healthy line *GH*; the reverse looking Zone 3 units at end *H* reset when breaker *K* opens. The forward looking Zone 2 units at end *G*, which operated when the fault at *K* started, also

Figure 12.12 Ideal blocking scheme.



(a) DISTANCE/TIME CHARACTERISTICS



(b) SIGNALLING CHANNEL SEND ARRANGEMENT (CONTACT LOGIC)



(c) SOLID STATE LOGIC OF SEND CIRCUIT

Figure 12.14 Blocking schemes using reverse-looking relays with offset.

reset when breaker *K* opens. If the blocking signal resets at end *G* before Zone 2 units reset, the breaker at end *G* may trip.

To avoid this possible maloperation, the resetting of the signal received element provided in the blocking scheme is time delayed.

The time delay unit with delayed resetting (*td*) is set to cover the time difference between the maximum resetting time of Zone 2 units and the minimum resetting time of reverse looking Zone 3 units and the signalling channel. So, if there is a momentary loss of the blocking signal during the current reversal, the time delay unit (*td*) does not have time to reset in the blocking mode trip circuit and no false tripping takes place.

## 12.5

The permissive over-reach scheme described in Section 12.3.3 can be arranged to operate on a directional comparison unblocking principle by providing additional circuitry in the signalling equipment. In this scheme, a continuous block (guard) signal is transmitted and when the over-reaching distance units operate, the frequency of the signal transmitted is shifted to an 'unblock' (trip) frequency. The receipt of the unblock frequency signal and the operation of over-reaching distance units allow aided tripping to occur. So the scheme is in principle similar to the permissive over-reach scheme.

The scheme is made more dependable than the standard permissive over-reach scheme by providing additional circuits in the receiver equipment to allow tripping to take place for internal faults even if the transmitted unblock signal is short-circuited by the fault. This is achieved by allowing aided tripping for a short time interval, typically 100 to 150 milliseconds, after the loss of both the block and the unblock frequency signals. After this time interval aided tripping is permitted only if the unblock frequency signal is

received. This arrangement gives the scheme better security than that of the blocking scheme, since tripping for external faults is possible only if the fault occurs within the above time interval of channel failure.

In this way the scheme has the dependability of a blocking scheme and the security of a permissive over-reach scheme. The scheme is generally preferred when power line carrier is used, except when continuous transmission of signal is not acceptable.

## 12.6

A weak infeed terminal cannot contribute sufficient fault current during internal fault conditions to operate the protection applied at that terminal. However, it is necessary to open the circuit breaker at the weak infeed terminal, since even a low fault infeed can maintain the fault. With permissive transfer trip and acceleration schemes, the protection at the strong infeed terminal will be unable to clear end-zone faults instantaneously unless a signal is received from the remote line end.

To maintain stability and achieve high speed auto-reclosing, it is essential that both the strong and weak infeed terminal breakers are opened instantaneously for faults anywhere within the line section.

The operation of each of the schemes described above is considered below, for weak infeed conditions at one terminal.

### 12.6.1

#### Permissive under-reach and acceleration schemes

In these schemes the Zone 1 units at the strong infeed terminal do not see end-zone faults. Due to the non-operation of Zone 1 units at both terminals, it is not possible to achieve instantaneous tripping for end-zone faults near the weak infeed terminal. Therefore these schemes are not suitable for this type of application.

### 12.6.2

#### Permissive over-reach scheme and directional comparison unblocking scheme

The over-reaching Zone 2 units at the strong infeed terminal operate and initiate the signalling channel for faults near the weak infeed terminal. Since there is no operation of protection at the weak infeed terminal, the protection at the strong infeed terminal does not receive a permissive tripping signal. Therefore the standard permissive over-reach scheme cannot provide instantaneous protection for end zone faults near the weak infeed terminal.

By providing additional logic in the distance scheme at the weak infeed terminal, it is possible to trip the breakers at both ends instantaneously for such faults. The Zone 3 units are set to look in the reverse direction to cover the reach of the Zone 2 units of the strong infeed end and voltage measuring units are used in the weak infeed logic circuits. The scheme is shown in Figure 12.15.

The received signal from the strong infeed terminal is echoed back to the remote terminal and is also used for tripping the weak infeed terminal breaker, provided the following conditions are satisfied.

- The reverse looking Zone 3 units have not operated. For faults behind the weak infeed terminal, the fault current is fed from the strong infeed end and reverse looking Zone 3 units would operate, inhibiting the weak infeed circuit.
- At least one of the voltage measuring units, connected between phase and neutral, has reset, which confirms that a fault condition exists.

Time delay circuits are provided in the weak infeed carrier send and trip circuits to prevent maloperation during cur-

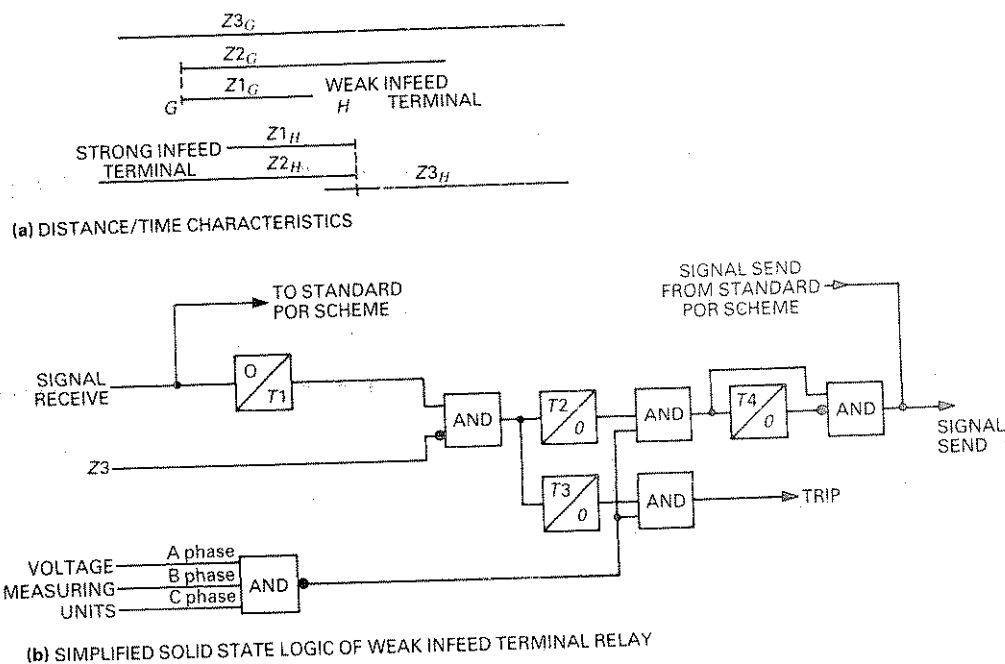


Figure 12.15 Weak infeed feature in permissive over-reach scheme.

rent reversal conditions associated with a fault in a parallel feeder.

Referring to Figure 12.8 and considering end  $H$  as a weak infeed terminal, the requirement of time delay circuits is explained as follows.

After the current reversal, the reverse looking Zone 3 units at the weak infeed terminal  $H$  and the over-reaching Zone 2 units at the strong infeed terminal  $G$ , which operated when the fault at  $K$  started, reset. The voltage units, which had reset and enabled the weak infeed circuit when the fault at  $K$  started, operate and inhibit the weak infeed circuit only after the tripping of breakers at both ends of the faulted circuit and the system voltage is restored to the normal value. Thus, the weak infeed trip circuit at  $H$  has to be delayed for a period  $T_3$  equal to the difference in the tripping times of breakers at  $J$  and  $K$ , plus the voltage measuring unit operation time, less the resetting time of Zone 3 units.

In the case of the weak infeed signal send circuit at  $H$ , a small time delay  $T_2$  is required to prevent tripping at  $G$  following the current reversal. This time is set to cover the difference between the maximum reset times of  $Z_2$  units at the remote end  $G$  and the sum of the minimum reset time of reverse looking  $Z_3$  units at  $H$  and the minimum signalling time.

For an internal fault near the strong infeed terminal and considering fast fault clearance, the received signal at the weak infeed terminal may reset before the time delay provided in the weak infeed trip circuit has expired. To achieve tripping of the breaker at the weak infeed terminal, it is necessary to provide a time delay  $T_1$  on reset of the 'received' signal, greater than the delay provided in the weak infeed trip circuit.

### 12.6.3

#### Blocking scheme

In this scheme, the protection at the strong infeed terminal will operate for all internal faults, since a blocking signal is not received from the weak infeed terminal end. In the case of external faults behind the weak infeed terminal, the reverse looking Zone 3 units at that end will see the fault

current fed from the strong infeed terminal and operate, initiating a block signal to the remote end.

So the relay at the strong infeed end operates correctly without the need for any additional circuits.

In the case of the weak infeed terminal end, the protection there cannot operate for internal faults and so tripping of that breaker is possible only by means of direct intertripping from the strong source end.

### 12.7

On normal two-terminal lines the main deciding factors in the choice of the type of scheme, apart from the reliability of the signalling channel previously discussed, are operating speed and the method of operation of the system.

If for instance high speed auto-reclosing is employed, then all transient faults, which are in the majority, will be cleared correctly by the blocking scheme even in the unlikely event of failure of the carrier channel. This can be seen from Figure 12.16 in which a transient fault is assumed to have occurred at point  $X$  on a line section adjacent to the protected feeder, all breakers being equipped with high speed reclosing relays.

If the carrier channel fails, breaker  $G$  may trip as well as breaker  $J$ , but both will reclose, thus restoring the system to normal. If a transfer trip scheme had been used in place of the blocking scheme only breaker  $J$  would have tripped

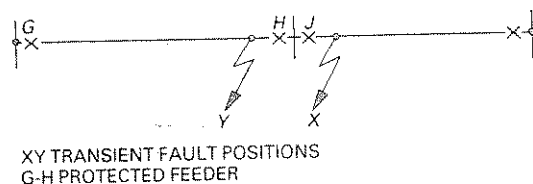


Figure 12.16 Illustration of fault positions.

and reclosed; in other words, the blocking scheme can cause an unnecessary trip and reclose operation of breaker *G*, in this case, but no wrong permanent tripping.

If, however, an internal transient fault occurs at *Y*, then, with the blocking scheme, both breakers *G* and *H* will trip simultaneously and reclose, restoring the system to normal. In the case of the transfer trip scheme, breaker *H* will trip in Zone 1 time but if the carrier channel fails, breaker *G* will trip in Zone 2 time and a successful reclosure will be impossible because the fault will be maintained from end *G* with the result that breaker *H* will reclose on to the fault and lock out.

Even if auto-reclosing is not applied a carrier channel is normally added because Zone 2 clearance times cannot be allowed. This is because of stability considerations; correct discriminative clearance of a fault is of little benefit if system stability is lost. This is possible with a time delayed clearance from one end as a result of channel failure on the transfer trip scheme.

The major advantage claimed for the permissive transfer trip scheme is speed, as the intentional time delays needed in the blocking schemes to ensure that the carrier signal has been received are not necessary. In blocking schemes using electromechanical relays a time delay was particularly necessary, as the operating times of the carrier starting elements could vary widely with different generating conditions and types of fault.

While the above argument in favour of the permissive transfer trip schemes may be valid from the relaying point of view, it is not necessarily true when the operation of the carrier channel is considered. If in-service testing is to be carried out, a time delay in the carrier trip circuit is needed, otherwise an external second zone fault occurring during a test would produce false tripping. Sufficient time is allowed for a fault detector to interrupt the testing function, so that the tripping signal can be proved authentic before the trip circuit is completed.

No additional time delays are required with blocking schemes during in-service testing. Scheme operating times for internal faults are unlikely to be affected by the time taken to remove a test signal as this is normally shorter than the time delay needed to allow a carrier blocking signal to arrive for an external fault.

The operation of a permissive over-reach scheme working on the directional comparison unblocking principle, as previously discussed, combines the security of the standard permissive over-reach scheme and the dependability of the blocking scheme.

## 12.5

Three-terminal lines as illustrated in Figure 12.17 can often be protected by a normal three-step distance scheme applied at each end of the feeder, but the zone of overlap of the first stage providing instantaneous tripping is usually much smaller than in the case of the two-terminal line. This is illustrated in Figure 12.18; because of this the use of a carrier link becomes more important.

In this case, the choice of the type of scheme is influenced much more by the configuration and mode of operation of the system; the various advantages and disadvantages are discussed in later sections of this Chapter.

Before dealing with the operational requirements of the relaying schemes it is worth considering briefly the requirements of the signalling channel. If a frequency shift carrier is used with a permissive under-reaching transfer trip scheme it is necessary to use a different guard frequency at each of the three terminals, so that the signals from two terminals can be identified definitely at the third. A common trip frequency is employed, tripping being allowed if

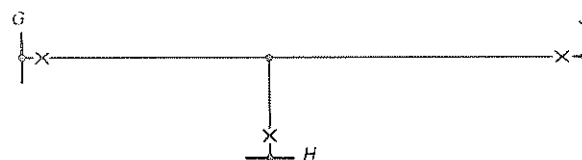
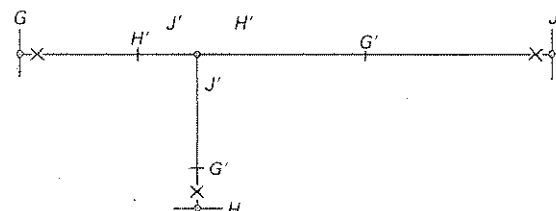


Figure 12.17 Typical three-terminal line.



G-G' ZONE 1 REACH OF RELAYS AT G  
H-H' ZONE 1 REACH OF RELAYS AT H  
J-J' ZONE 1 REACH OF RELAYS AT J  
H'-J'-J' FAULT ZONE IN WHICH HIGH SPEED CLEARANCE FROM ALL TERMINALS IS ACHIEVED WITHOUT CARRIER.

Figure 12.18 Coverage of typical three terminal line with distance relays.

the trip signal is received with only one guard signal. This is necessary because the tripping signal is initiated and the guard signal removed by the operation of the Zone 1 relay of the distance scheme at any end. If a common guard signal were used, it would be necessary for the Zone 1 relays at two ends of the feeder to operate before tripping could take place at the third terminal for a fault outside Zone 1 at that end. This is not always possible, because of varying feeder lengths and under-reaching by the distance measuring relays caused by infeeds.

If an over-reaching transfer trip scheme, that is, one in which the carrier initiating relay is set to over-reach the section, were used, it would be necessary to use a duplex carrier link between each pair of stations.

This is necessary to ensure that tripping does not take place at one end until it is certain that the carrier starting relays at both the remaining terminals have operated, making certain that the fault is within the line section.

This method of signalling is not only expensive but also occupies a relatively large bandwidth; because of the shortage of available carrier frequencies this is not usually acceptable.

Unlike the transfer trip schemes, a blocking scheme need only use a simple on/off single carrier channel, as the function of the signal is to block tripping rather than to cause it. However, steps must be taken to ensure that the locally derived signal does not under any circumstances cancel the signal received from the far end. In the case of the three-terminal line, additional attenuation in the transmitted signal is caused by reflection at the 'tee' junction and, in order to obtain maximum reliable operation, there is an advantage in using a blocking scheme where transmission is always over a healthy line and attenuation due to an internal fault does not have to be considered.

The problems to be overcome in the protection of three-terminal lines are numerous; it is far more difficult to protect a line of this nature satisfactorily for all configurations and system conditions than it is to do the same for the simple two-terminal line. The various features of transfer trip and blocking schemes will be considered in relation to these problems.

### 12.8.1

#### Transfer trip schemes

Only the under-reaching scheme will be considered, as the type of carrier channel required for the over-reaching scheme severely limits its possible applications. In the under-reaching scheme, the Zone 1 relays at each terminal, set to approximately 80% of the shorter feeder length between any two ends, are used to initiate the intertripping signal. The operation of the Zone 1 relay at any one terminal is enough to give virtually simultaneous instantaneous clearance of all internal faults.

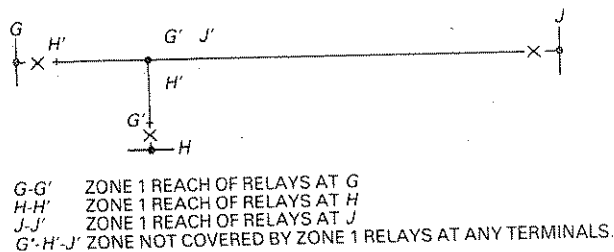


Figure 12.19 Example of three-terminal line illustrating non-overlap of Zone 1 relays.

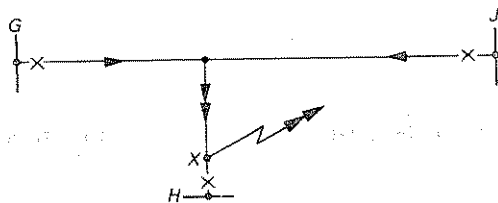


Figure 12.20 Three-terminal line illustrating condition of fault close to a terminal at which there is no infeed.

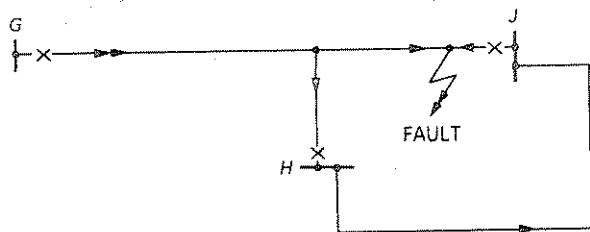


Figure 12.21 Example of fault current flowing out of one terminal for an internal fault.

There are two cases in which this is not possible; the first is shown in Figure 12.19. In this case, because of the relative feeder lengths, it is not possible to obtain overlap of the reaches of the Zone 1 relays at each end. This leaves a section of the circuit in which fault clearance will be in Zone 2 time from each end with the possibility of sequential Zone 2 clearance at one end, depending on the ratio of infeeds. The second case is shown in Figure 12.20. Here it is assumed either that the breaker at  $H$  is open or that there is no infeed at the busbars at  $H$ ; should a fault occur at  $X$ , no intertrip signal can be sent by the Zone 1 relay at  $H$  because it cannot operate. Again the fault will be cleared in second zone time by the relays  $G$  and  $J$ .

Where the more usual permissive under-reaching scheme is used, a further difficulty arises if current is outfed from the protected section at one of the terminals,  $H$ , and fed back in at another,  $J$ , as illustrated in Figure 12.21. When this happens the fault detector used to monitor the received tripping signal may not operate if it is the usual

rho or offset type and may therefore prevent tripping of the breaker at terminal  $H$  until the breaker at  $J$  has operated. In addition, before simultaneous instantaneous clearing of any internal faults can take place, not only must the Zone 1 relay at one end operate but the fault detectors at all ends must operate as well, which, again, will restrict its application in a few instances.

### 12.8.2

#### Blocking schemes

The normal type of blocking scheme with characteristics as shown in Figure 12.13, overcomes to some extent the problems, outlined previously, of the transfer trip schemes. As the tripping at each terminal is initiated by the Zone 2 rather than by the Zone 1 relays as is the case with the transfer trip under-reach scheme, high speed tripping at all three terminals can be expected for a much wider variation of the line lengths and magnitude of infeeds.

High speed tripping from all terminals can be achieved for a fault near one terminal where there is no infeed, as, in this situation, no blocking signal can be initiated from this terminal and, providing the fault is within the reach of the relays at the other two terminals, instantaneous tripping will take place. If the infeed from one terminal predominates, sequential tripping at the other terminal may have to be accepted.

The major disadvantage of the standard blocking scheme is evident when the condition depicted in Figure 12.21 arises. Here, the reverse-looking fault detector at terminal  $H$  will initiate a blocking signal to the other two terminals, preventing tripping until after normal Zone 2 time has expired.

### 12.9

Having studied the various types of distance carrier schemes available and their limitations when applied to two and three terminal feeders, it is possible to stipulate the requirements of the ideal scheme.

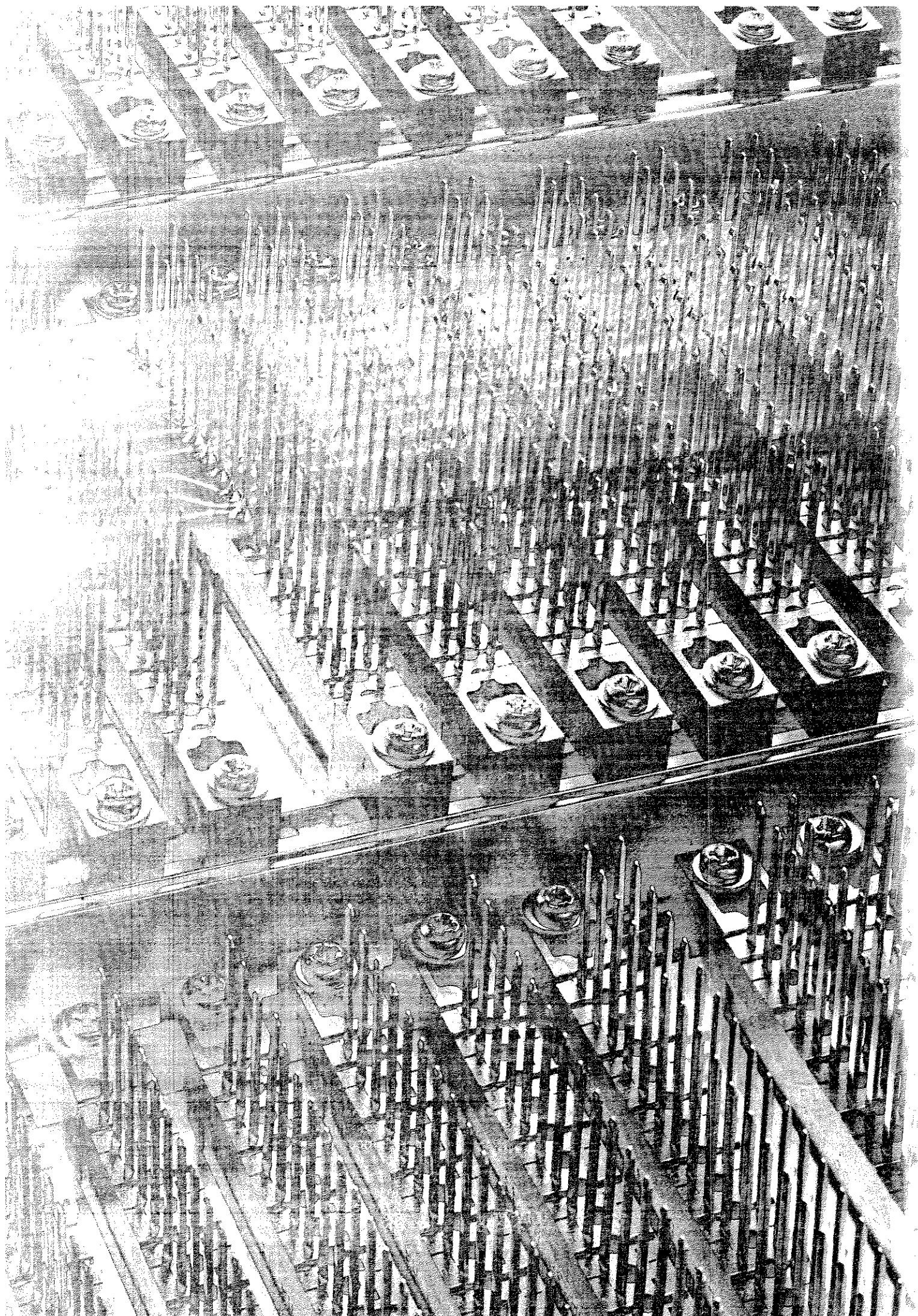
From the signalling point of view, it follows that the less attenuation there is in the transmission path, the more reliable the transmission can be for a given length of feeder; that is, the signal to noise ratio can be increased. In the transfer trip schemes, attenuation due to the fault is unpredictable and variable and because of this, the worst conditions must be assumed if absolute reliability is to be realized. In blocking schemes this variable factor does not exist.

From the relaying aspect, there are advantages in the blocking and the permissive over-reach schemes, since the over-reaching units which initiate tripping can cover high resistance faults and a wide variation of fault infeeds. When one of the terminals has no infeed or a weak infeed, the permissive over-reach scheme, when provided with the weak infeed circuit facility, has advantages over the blocking and permissive under-reach schemes, since breakers at both the terminals can be opened instantaneously.

For three terminal lines, there are decided advantages in the blocking scheme. The one major drawback in the application of blocking schemes to three terminal lines is the possibility of outfeed at one terminal during internal faults, causing a blocking signal to be sent to the other terminals. The provision of an independent Zone 1 would overcome this to a large extent as this would in the majority of cases allow tripping of the breaker nearest the fault followed by sequential operation of breakers at other line ends.

Modern distance relays are provided with a choice of several schemes in the same relay, to be selected by the user to suit the requirements.







# Protection of parallel and multi-ended feeders

13.1  
13.2

## 13.1

If two circuits are supported on the same towers or are otherwise in close proximity over the whole part of their length, there is a mutual coupling between the two circuits. The positive and negative sequence coupling between the two feeders is small and is, therefore, usually neglected. The zero sequence coupling, on the other hand, can be strong and its effect cannot be ignored.

Types of protection that use current only, for example power line carrier phase comparison systems and pilot wire differential systems, are not affected by the coupling between the feeders, whereas types using current and voltage, especially distance protection, are certainly influenced by this phenomenon and its effect requires special consideration.

### 13.1.1

#### Behaviour of distance relays with earth faults on the protected feeder

When an earth fault occurs in the system, the voltage applied to a relay in one circuit includes an induced voltage proportional to the zero sequence current in the other circuit. As the current distribution in the two circuits is unaffected by the presence of mutual coupling, no similar variation in the current applied to the relay takes place and, consequently, the relay measures the impedance to the fault incorrectly. Whether the apparent impedance to the fault is greater or less than the actual impedance depends on the direction of the current flow in the healthy circuit. For the common case of two circuits, *G* and *H*, connected at the local and remote busbars, as shown in Figure 13.1, the impedance measured by a distance relay, with the normal zero sequence current compensation from its own feeder, is given by:

$$Z_G = nZ_{L1} \left\{ 1 + \frac{(I_{H0}/I_{G0}) M}{2(I_{G1}/I_{G0}) + K} \right\} \quad \dots \text{Equation 13.1}$$

The true impedance to the fault is  $nZ_{L1}$  where *n* is the per unit fault position measured from *R* and  $Z_{L1}$  is the positive sequence impedance of a single circuit. The 'error' in measurement is determined from the fraction inside the bracket; this varies with the positive and zero sequence currents in circuit *G* and the zero sequence current in circuit *H*. These currents are expressed below in terms of the line and source parameters:

$$\frac{I_{H0}}{I_{G0}} = \frac{nZ''_{S0} - (1-n)Z'_{S0}}{(2-n)Z''_{S0} + (1-n)(Z'_{S0} + Z_{L0} + Z_{M0})}$$

$$I_{G1} = \frac{(2-n)Z''_{S1} + (1-n)(Z'_{S1} + Z_{L1})}{2(Z'_{S1} + Z''_{S1}) + Z_{L1}} I_1$$

$$I_{G0} = \frac{(2-n)Z''_{S0} + (1-n)(Z'_{S0} + Z_{L0} + Z_{M0})}{2(Z'_{S0} + Z''_{S0}) + Z_{L0} + Z_{M0}} I_0$$

NOTE. For earth faults  $I_1 = I_0$

All symbols in the above expressions are either self-explanatory from Figure 13.1 or have been introduced in Chapter 11, except for  $M$  and  $Z_{M0}$ .  $M$  is the ratio  $Z_{M0}/Z_{L1}$  where  $Z_{M0}$  is the zero sequence mutual impedance between the two circuits. Using the above formulae, families of reach curves may be constructed of which Figure 13.2 is typical. In this figure  $n'$  is the effective per unit reach of a relay set to protect 80% of the line. It has been assumed that an infinite source MVA prevails at the busbar at each line end, that is,  $Z'_{S1}$  and  $Z''_{S1}$  are both zero. A family of curves of constant  $n'$  has been plotted for variations in the source zero sequence impedances  $Z'_{S0}$  and  $Z''_{S0}$ .

It can be seen from Figure 13.2 that the relay can under-reach or over-reach, according to the relative values of the zero sequence source to line impedance ratios; the extreme effective per unit reaches for the relay are 0.67 and 1. Relay over-reach is not a problem, as the condition being examined is a fault in the protected feeder, for which relay operation is desirable. It can also be seen from Figure 13.2 that the relay is more likely to under-reach. However, it should be noted that the relay located at the opposite end of the line tends to over-reach when the local relay under-reaches. As a result, the zone 1 characteristic of the relays at both ends of the feeder will overlap for an earth fault anywhere in the feeder. This means that high speed operation can be obtained with a transfer trip, under-reach type distance scheme. Consequently, special ways of compensating for the effect of zero sequence mutual impedance are not considered necessary unless the relay in question has to measure the line impedance to the fault point accurately, as, for example, does a distance-to-fault locator. Nevertheless, some manufacturers compensate for the effect of the mutual impedance in distance relays. This is done by injecting into the relay a certain amount of zero sequence current from the parallel feeder; the amount is determined as follows:

For a phase to earth solid fault at the theoretical reach of the relay, the voltage and current in the faulty phase at the relaying point are given by:

$$\left. \begin{aligned} V_G &= I_{G1}Z_{L1} + I_{G2}Z_{L2} + I_{G0}Z_{L0} + I_{H0}Z_{M0} \\ I_G &= I_{G1} + I_{G2} + I_{G0} \end{aligned} \right\} \dots \text{Equation 13.2}$$

The voltage and current fed into the relay are given by:

$$\left. \begin{aligned} V_R &= V_G \\ I_R &= I_G + K_R I_{G0} + K_M I_{H0} \end{aligned} \right\} \dots \text{Equation 13.3}$$

where  $K_R$  is the residual compensation factor

$K_M$  is the mutual compensation factor

For the relay to measure the line impedance accurately, the following condition must be met:

$$\frac{V_R}{I_R} = Z_{L1}$$

Thus:

$$K_R = \frac{Z_{L0} - Z_{L1}}{Z_{L1}}$$

$$K_M = \frac{Z_{M0}}{Z_{L1}}$$

\* Davison, E. B. and Wright, A. Some factors affecting the accuracy of distance type protective equipment under earth fault conditions. Proc. IEE Vol. 110, No. 9, Sept. 1963, pp. 1678-1688.

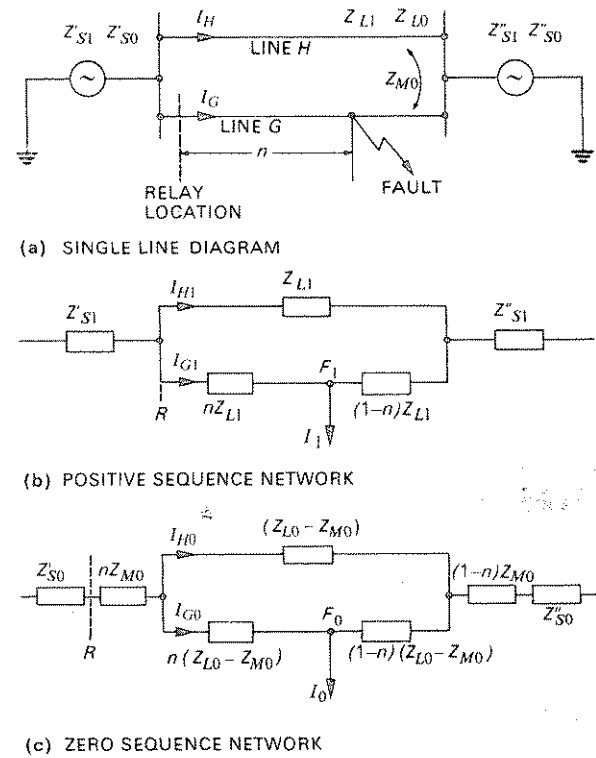


Figure 13.1 General parallel line circuit fed from both ends

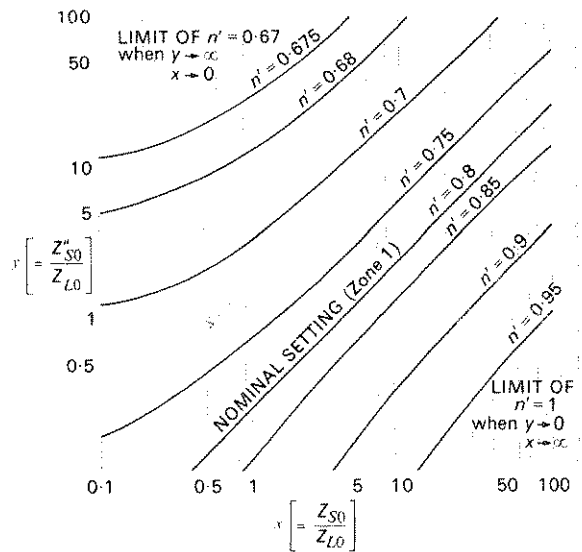


Figure 13.2 Typical reach curves illustrating the effect of mutual coupling (infinite busbar sources at both ends, that is  $Z'_{S1} = Z''_{S1} = 0$ ).

### 13.1.2

#### Behaviour of distance relays with earth faults on the parallel feeder

Although distance relays with mutual compensation measure the correct distance to the fault, they may not operate correctly if the fault occurs in the adjacent feeder. Davison and Wright\* have shown that, while distance relays without mutual compensation will not over-reach

faults outside the protected feeder, the relays may see faults in the adjacent feeder if mutual compensation is provided. The amount of over-reach is highest when  $Z_{S1}'' = Z_{S2}'' = Z_{S0}'' = \infty$ . Under these conditions, faults occurring in the first 43% of feeder G will appear to the distance relay in feeder H to be within its operating zone 1. Consequently, mutual compensation for distance relays was not recommended until improved techniques had been devised. These are described in Section 11.29.

### 13.1.3 Relay behaviour with single-circuit operation

If only one of the parallel feeders is in service, the protection in the remaining feeder measures the fault impedance correctly, except when the feeder which is not in service is earthed at both ends. In this case, the zero sequence impedance network is as shown in Figure 13.3.

Humpage and Kandil† have shown that the apparent impedance presented to the relay under these conditions is given by:

$$Z_R = Z_{L1} - \frac{I_{G0} Z_{M0}^2}{I_R Z_{L0}} \quad \dots \text{Equation 13.4}$$

where  $I_R$  is the current fed into the relay  $= I_G + K_R I_{G0}$

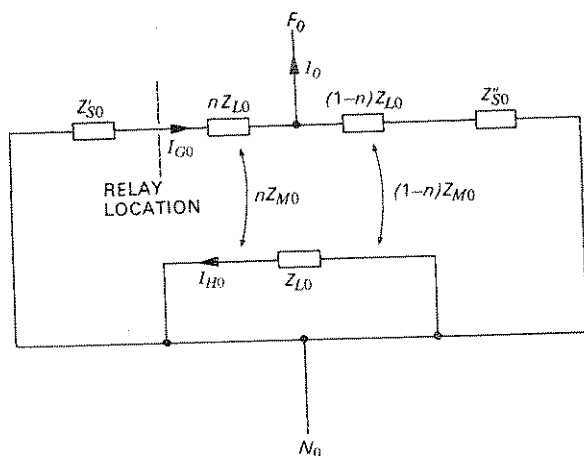


Figure 13.3 Zero sequence impedance network during single circuit operation.

The ratio  $I_{G0}/I_R$  varies with the system conditions, reaching a maximum when the system is earthed behind the relay with no generation at that end. In this case, the ratio  $I_{G0}/I_R$  is equal to  $Z_{L1}/Z_{L0}$ , and the apparent impedance presented to the relay is:

$$Z_R = Z_{L1} \left( 1 - \frac{Z_{M0}^2}{Z_{L0}^2} \right)$$

It is apparent from the above formulae that the relay has a tendency to over-reach, so care should be taken when

zone 1 settings are selected for the distance protections of lines in which this condition may be encountered.

Typical values of zero sequence line impedances for the HV systems in the United Kingdom are given in Table 13.1, where the maximum per unit over-reach error  $(Z_{M0}/Z_{L0})^2$  is also given. It should be noted that the over-reach values quoted in this table are maxima and will be found only in rare cases. In most cases, there will be generation at both ends of the feeder and the amount of over-reach will therefore be reduced. In the calculations carried out by Humpage and Kandil, with more realistic conditions, the maximum error found in a 400kV double circuit line was 18.59%.

### 13.2

A multi-ended feeder is defined as one having three or more terminals, with either load or generation, or both, at any terminal. Those terminals with load only are usually known as 'taps'.

The simplest multi-terminal feeders are three-ended, and are generally known as tee'd feeders. This is the type most commonly found in practice.

The protective schemes described previously for the protection of two-ended feeders can also be used for multi-ended feeders. However, the problems involved in the application of these schemes to multi-ended feeders are much more complex and require special attention.

The basic forms of protection which can be used with multi-ended feeders are: differential relays, phase comparison schemes, directional relays and distance relays, each also using some form of signalling channel, such as power line carrier or d.c. pilots. The specific problems that may be met when applying these protections to multi-ended feeders are discussed in the following sections.

#### 13.2.1

##### A.c. pilot wire protection

A.c. pilot wire relays provide a low-cost fast protection; they are insensitive to power swings and, owing to their relative simplicity, their reliability is excellent.

The limitations of pilot wire relays found on plain feeder protection are also present when these relays are applied to multi-ended feeders; for example, the length of feeder that can be protected is limited by the characteristics of the pilot wires. The pilot wire resistance increases with the length of the feeder and, as seen by the protection, appears increasingly like an open circuit. Similarly, the shunt capacitance also increases and tends to become, in effect, an a.c. short circuit across the pilots. If certain limiting values of pilot resistance and capacitance are exceeded, both loss of sensitivity for internal faults and maloperation for external faults may occur. When pilot wire protection is applied to plain feeders and the equipment at each of the two ends is identical, the protection should remain stable for through-fault conditions even if the equipment is non-linear, since the current at both ends is practically the same.

| Line voltage | Conductor size<br>(sq. in.) | Equivalent metric c.s.a.<br>(sq. mm) | Zero sequence mutual impedance $Z_{M0}$ |              | Zero sequence line impedance $Z_{L0}$ |              | Per unit over-reach error<br>$(Z_{M0}/Z_{L0})^2$ |
|--------------|-----------------------------|--------------------------------------|-----------------------------------------|--------------|---------------------------------------|--------------|--------------------------------------------------|
|              |                             |                                      | ohms/mile                               | ohms/km      | ohms/mile                             | ohms/km      |                                                  |
| 132kV        | 0.4                         | 258                                  | 0.3 + j0.81                             | 0.19 + j0.5  | 0.41 + j1.61                          | 0.25 + j1.0  | 0.264                                            |
| 275kV        | 2 × 0.4                     | 516                                  | 0.18 + j0.69                            | 0.11 + j0.43 | 0.24 + j1.3                           | 0.15 + j0.81 | 0.292                                            |
| 400kV        | 4 × 0.4                     | 1032                                 | 0.135 + j0.60                           | 0.08 + j0.37 | 0.16 + j1.18                          | 0.1 + j0.73  | 0.266                                            |

Table 13.1 Maximum over-reach errors found during single circuit working.

† Humpage, W. D. and Kandil, M. S. Distance protection performance under conditions of single-circuit working in double-circuit transmission lines. Proc. IEE. Vol. 117. No. 4, April 1970, pp. 766-770.

For tee'd feeders, the currents for an external earth fault will not usually be the same. It is, therefore, essential that the protection be linear for any current up to the maximum through-fault value. As a result, the voltage in the pilots during fault conditions cannot be kept to low values, and pilot wires with suitable insulation grade, usually 250V, are required.

Two tee'd feeder schemes each using pilot wires are described in Section 10.8.5. They are the Translay system type HOA4 and the type DSB7 scheme using moving coil relays.

### 13.2.2

#### Power line carrier phase comparison schemes

The operating principle of these protective schemes has already been covered in detail in Sections 10.9 and 10.10. It involves comparing the phase angles of signals derived from a combination of the sequence currents at each end of the feeder. When the phase angle difference exceeds a pre-set value, the 'trip angle', a trip signal is sent to the corresponding circuit breakers. In order to prevent incorrect operation for external faults, two different detectors, set at different levels, are used. The low-set detector starts the transmission of carrier signal, while the high-set detector is used to control the trip output. Without this safeguard, the scheme could operate incorrectly for external faults because of operating tolerances of the equipment and the capacitive current of the protected feeder. This condition is worse with multi-terminal feeders, since the currents at the feeder terminals can be very dissimilar for an external fault. In the case of the three-terminal feeder in Figure 13.4, if incorrect operation is to be avoided, it is necessary to make certain that the low-set detector at end *G* or end *H* is energized when the current at end *J* is high enough to operate the high-set detector at that end. As only one low-set starter, at end *G* or end *H*, needs to be energized for correct operation, the most unfavourable condition will be when currents  $I_G$  and  $I_H$  are equal. To maintain stability under this condition, the high-set to low-set setting ratio of the fault detectors needs to be twice as large as that required when the scheme is applied to a plain feeder. This results in a loss of sensitivity, which may make the equipment unsuitable if the minimum fault level of the power system is low.

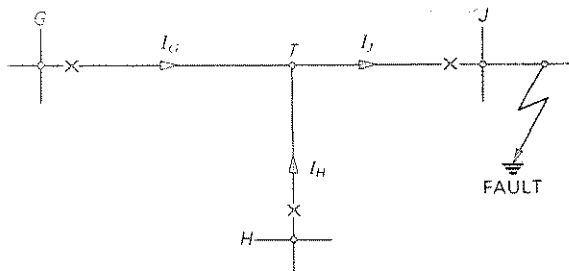


Figure 13.4 External fault conditions.

A further unfavourable condition is that illustrated in Figure 13.5. If an internal fault occurs near one of the ends of the feeder (end *H* in Figure 13.5) and there is little or no generation at end *J*, the current at this end may be flowing outwards. The protection is then prevented from operating, since the fault current distribution is similar to that for an external fault; see Figure 13.4. The fault can be cleared only by the back-up protection and, if high speed of operation is required, an alternative type of primary protection must be used.

A point which should also be considered when applying this scheme is the attenuation of carrier signal at the 'tee' junctions. This attenuation is a function of the relative impedances of the branches of the feeder at the carrier

frequency, including the impedance of the receiving equipment. When the impedances of the second and third terminals are equal, a power loss of 50% takes place. In other words, the carrier signal sent from terminal *G* to terminal *H* is attenuated by 3 dB by the existence of the third terminal *J*. If the impedances of the two branches corresponding to terminals *H* and *J* are not equal, the attenuation may be either greater or less than 3 dB.

### 13.2.3

#### Distance relays

Distance protection is widely used at present for tee'd feeder protection. However, its application is not straightforward, requiring careful consideration and systematic checking of all the conditions described later in this section.

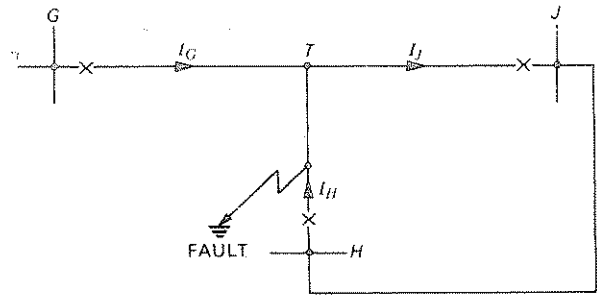


Figure 13.5 Internal fault with current flowing out at one line end.

Most of the problems found when applying distance protection to tee'd feeders are common to all schemes. A preliminary discussion of these problems will be a help in the assessment of the performance of the different types of distance schemes.

#### Apparent impedance seen by distance relays

The most well-known problem is the effect of the current infeeds in the branches of the feeder on the impedance seen by the relays.

Referring to Figure 13.6, for a fault at the busbars of the substation *H*, the voltage  $V_G$  at the busbars *G* is given by:

$$V_G = I_G Z_{LG} + I_H Z_{LH}$$

so the impedance  $Z_G$  seen by the distance relay at terminal *G* is given by:

$$Z_G = \frac{V_G}{I_G} = Z_{LG} + \frac{I_H}{I_G} Z_{LH} \quad \dots \text{Equation 13.5}$$

or

$$Z_G = Z_{LG} + Z_{LH} + \frac{I_J}{I_G} Z_{LH}$$

Here, the apparent impedance presented to the relay has been modified by the term  $(I_J/I_G)Z_{LH}$ . If the pre-fault load is zero, the currents  $I_G$  and  $I_J$  are in phase and their ratio is a real number. The apparent impedance presented to the relay in this case can be expressed in terms of the source impedances as follows:

$$Z_G = Z_{LG} + Z_{LH} + \frac{(Z_{SG} + Z_{LG})}{(Z_{SJ} + Z_{LJ})} Z_{LH}$$

The magnitude of the third term in this expression is a function of the total impedances of the branches *G* and *J*, and can reach a relatively high value when the fault current contribution of branch *J* is much larger than that of branch *G*. Figure 13.7 illustrates how a distance relay with a mho characteristic, set to 120% of the protected feeder *GH*, fails to see a fault at the remote busbar *H*. The 'tee' point *T* in this example is halfway between substations *G* and *H* ( $Z_{LG}$

$= Z_{LH}$ ) and the fault currents  $I_G$  and  $I_J$  have been assumed to be identical in magnitude and phase angle. With these conditions, the fault appears to the relay located at  $H'$  instead of to that at  $H$ .

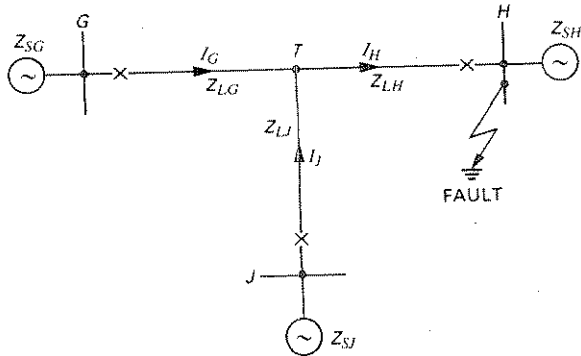


Figure 13.6 Fault at substation H busbars.

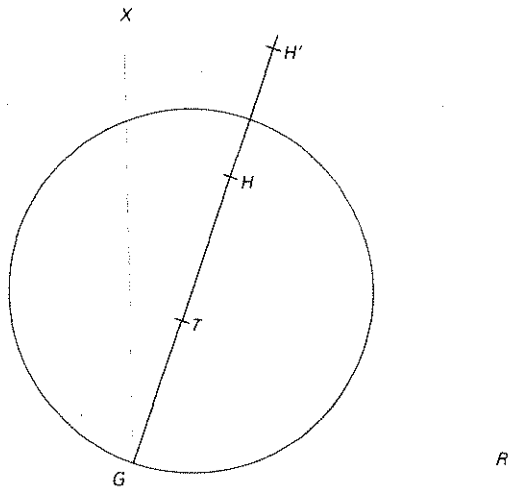


Figure 13.7 Apparent impedance presented to the relay at substation G for a fault at substation H busbars.

The under-reaching effect in tee'd feeders can be found for any kind of fault. For the sake of simplicity, the equations and examples mentioned so far have been for balanced faults only. For unbalanced faults, especially those involving the earth, the equations become somewhat more complicated, as the ratios of the sequence fault current contributions at terminals G and J may not be the same. An extreme example of this condition is found when the third terminal is a tap with no generation but with the star point of the primary winding of the transformer connected directly to earth, as shown in Figure 13.8. The corresponding sequence networks are illustrated in Figure 13.9, from which it can be seen that, while the presence of the tap has little effect in the positive and negative sequence networks, the zero sequence impedance of the branch actually shunts the zero sequence current in the branch G. As a result, the distance relay located at the terminal G tends to under-reach. One solution to this problem consists of increasing the residual current compensating factor in the distance relay, in order to compensate for the reduction in zero sequence current. This solution has two possible limitations:

i. The distance relay will tend to over-reach when the transformer is not connected, and may operate for faults outside the protected zone.

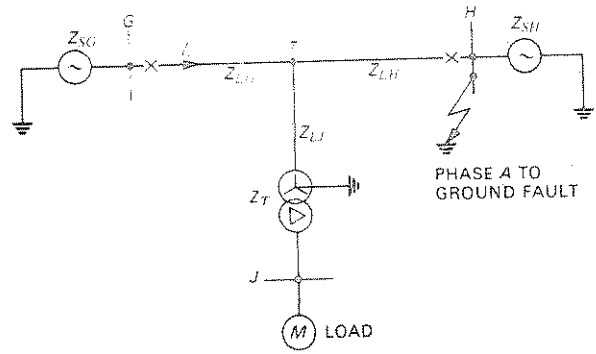


Figure 13.8 Transformer tap with primary winding solidly earthed.

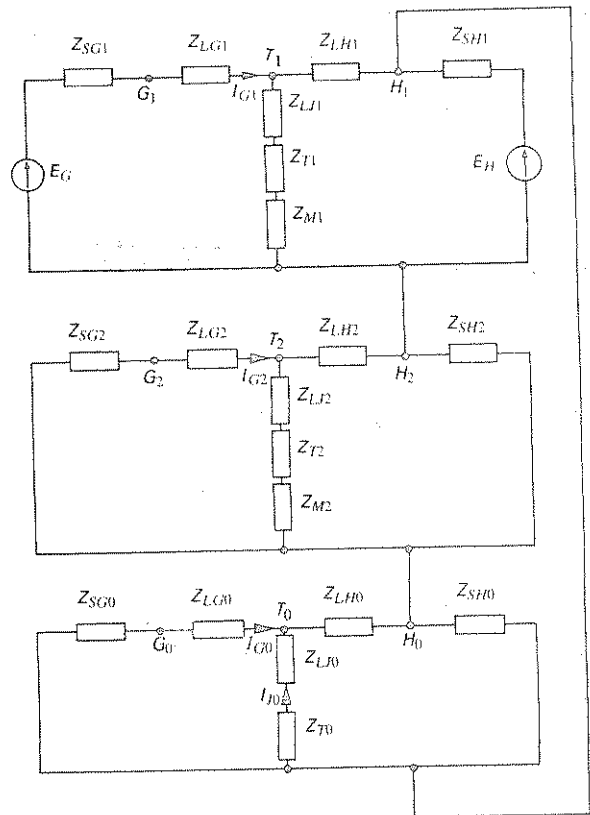


Figure 13.9 Sequence networks for a phase A to ground fault at busbar H in the system shown in Figure 13.8.

ii. The inherent possibility of maloperation of the earth fault distance relays for earth faults behind the relay location increases if the residual compensating factor is increased.

#### Effect of pre-fault load

In all the previous arguments and conclusions it has been assumed that the power transfer between terminals of the feeder immediately before the fault occurred was zero. If this is not the case, the fault currents  $I_G$  and  $I_J$  in Figure 13.6 may not be in phase, and the factor  $I_J/I_G$  in the equation for the impedance seen by the relay at G, will be a complex quantity with a positive or a negative phase angle according to whether the current  $I_J$  leads or lags the current  $I_G$ . For the fault condition previously considered in Figures 13.6 and 13.7, the pre-fault load current may

displace the impedance seen by the distance relay to points such as  $H'_1$  or  $H'_2$ , shown in Figure 13.10, according to the phase angle and the magnitude of the pre-fault load current. Humpage and Lewis\* have analyzed the effect of pre-fault load in the impedances seen by distance relays for typical cases. Their results and conclusions point out some of the limitations of certain relay characteristics and schemes.

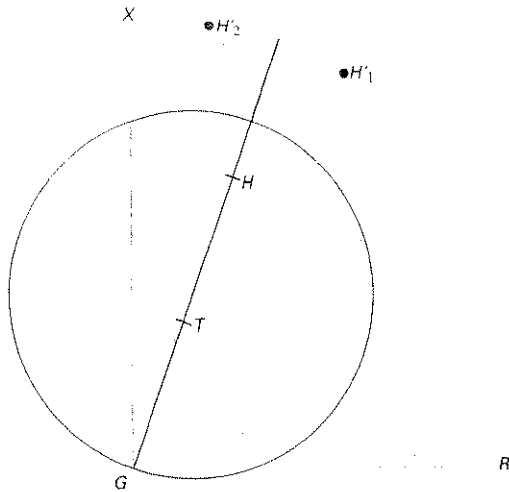


Figure 13.10 Effect of the pre-fault load on the apparent impedance presented to the relay.

#### Effect of the fault current flowing outwards at one terminal

Up to this point it has been assumed that the fault currents at terminals  $G$  and  $J$  flow into the feeder for a fault at the busbar  $H$ . Under some conditions, however, the current at one of those terminals may flow outwards instead of inwards. A typical case is illustrated in Figure 13.11; that of a parallel tapped feeder with one of the ends of the parallel circuit open at terminal  $G$ . As the currents  $I_G$  and  $I_J$  now have different signs, the factor  $I_J/I_G$  becomes negative. Consequently, the distance relay at terminal  $G$  sees an impedance smaller than that of the protected feeder, ( $Z_G + Z_H$ ), and therefore has a tendency to over-reach. In some cases the apparent impedance presented to the relay may be as low as 50% of the impedance of the protected feeder, and even lower if other lines exist between terminals  $H$  and  $J$ .

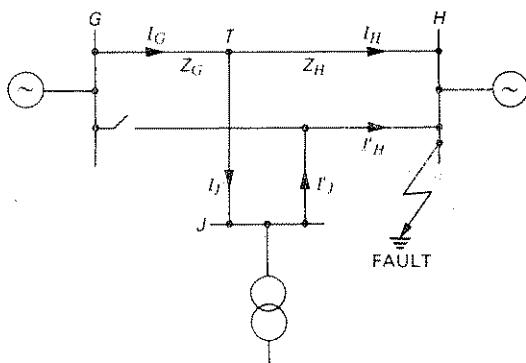


Figure 13.11 Fault at busbar  $H$  with current flowing out at terminal  $J$ .

If the fault is internal to the feeder and close to the busbars  $H$ , as shown in Figure 13.12, the current at terminal  $J$  may still flow outwards. As a result, the fault appears as an

\* Humpage, W. D. and Lewis, D. W. *Distance protection of tee'd circuits*. Proc. IEE, Vol. 114, No. 10, Oct. 1967, pp. 1483-1498.

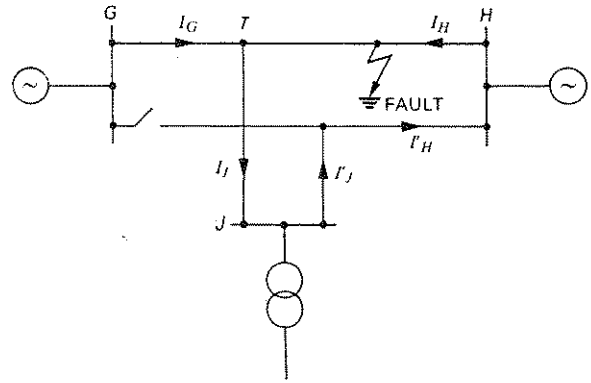


Figure 13.12 Internal fault near busbar  $H$  with current flowing out at terminal  $J$ .

external fault to the distance relay at terminal  $J$ , which fails to operate.

#### Maloperation with reverse faults

Earth fault distance relays with a directional characteristic, for example a mho characteristic, tend to lose their directional properties under reverse unbalanced fault conditions, which arise mainly from earth faults, if the current flowing through the relay is high and the relay setting relatively large. When the distance relays are applied to plain feeders, this problem is not normally present. Large settings are usually associated with relatively long feeders, and the impedance of the feeder tends to reduce the fault current for reverse fault conditions below the critical level. For tee'd feeders, on the other hand, the relay setting and the reverse fault current are not related, the first being a function of the maximum line length and the second depending mainly on the impedance of the shortest feeder and the fault level at that terminal. For instance, referring to Figure 13.13, the setting of the relay at terminal  $G$  will depend on the impedance ( $Z_G + Z_H$ ) and the fault current infeed  $I_J$ , for a fault at  $H$ , while the fault current  $I_G$  for a reverse fault may be quite large if the  $T$  point is near the terminals  $G$  and  $J$ .

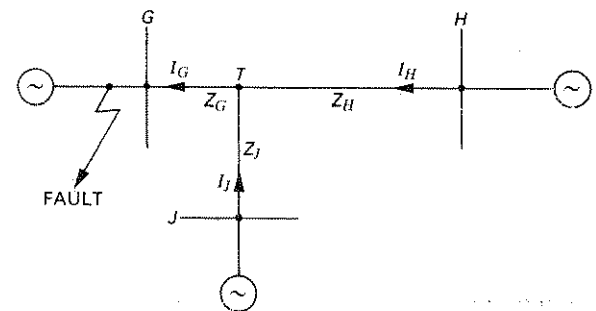


Figure 13.13 External fault behind the relay at terminal  $G$ .

A summary of the main problems met in the application of distance protection to tee'd feeders is given in Table 13.2.

#### 13.2.4 Distance schemes

The schemes which have been described in Chapter 12 for the protection of plain feeders may also be used for tee'd feeder protection. However, the applications of some of these schemes are much more limited in this case.

Distance schemes can be subdivided into two main

| Case | Description                                                                               | Relevant figure number |
|------|-------------------------------------------------------------------------------------------|------------------------|
| 1    | Under-reaching effect for internal faults due to current infeed at the T point.           | 13.6 to 13.9           |
| 2    | Effect of pre-fault load on the impedance 'seen' by the relay.                            | 13.10                  |
| 3    | Over-reaching effect for external faults, due to current flowing outwards at one terminal | 13.11                  |
| 4    | Failure to operate for an internal fault, due to current flowing out at one terminal.     | 13.12                  |
| 5    | Incorrect operation for an external fault, due to high current fed from nearest terminal. | 13.13                  |

Table 13.2 Main problems met in the application of distance protection to tee'd feeders.

groups: transfer trip schemes and blocking schemes. The usual considerations when comparing these schemes are security, that is, no operation for external faults, and dependability, that is, assured operation for internal faults.

In addition, it should be borne in mind that transfer trip schemes require fault current infeed at all the terminals to achieve high speed protection for any fault in the feeder. This is not the case with blocking schemes. While it is rare to find a plain feeder in high voltage systems where there is current infeed at one end only, it is not difficult to envisage a tee'd feeder with no current infeed at one end, for example when the tee'd feeder is operating as a plain feeder with the circuit breaker at one of the terminals open. Nevertheless, transfer trip schemes are also used for tee'd feeder protection, as they offer some advantages under certain conditions.

#### Transfer trip under-reach schemes

The main requirement for transfer trip under-reach schemes is that the zone 1 of the protection, at one end at least, shall see a fault in the feeder. In order to meet this requirement, the zone 1 characteristics of the relays at different ends must overlap, either the three of them or in pairs. Cases 1, 2 and 3 in Table 13.2 should be checked when the settings for the zone 1 characteristics are selected. If the conditions mentioned in case 4 are found, direct transfer trip may be used to clear the fault; the alternative is sequential clearance of the fault, that is, the fault is cleared sequentially at end J when the fault current  $I_f$  reverses after the circuit breaker at terminal H has opened; see Figure 13.12.

Transfer trip schemes may be applied to feeders which have branches of similar length. If one or two of the branches are very short, and this is often the case in tee'd feeders, it may be difficult or impossible to make the zone 1 characteristics overlap. Alternative schemes are then required.

Another case for which under-reach schemes may be advantageous is the protection of tapped feeders, mainly when the tap is short and is not near one of the main terminals. Overlap of the zone 1 characteristics is then easily achieved, and the tap does not require a protective terminal.

#### Transfer trip over-reach schemes

For correct operation when internal faults occur, the relays at the three ends should see a fault at any point in the feeder. This condition is often difficult to meet, since the impedance seen by the relays for faults at one of the remote ends of the feeder may be too large, as in case 1 in Table 13.2, increasing the possibility of maloperation for reverse faults, case 5 in Table 13.2. In addition, the relay characteristic might encroach on the load impedance.

These considerations, in addition to the signalling channel requirements mentioned later on, make transfer trip over-reach schemes unattractive for tee'd feeder protection.

#### Blocking schemes

Blocking schemes are particularly suited to the protection

of multi-ended feeders, since high speed operation can be obtained with no fault current infeed at one or more terminals.

For external faults, a blocking signal is initiated at the terminal nearest to the fault, and the operation of the protection at the other terminals is prevented when this signal is received. When the fault is internal, no blocking signal is initiated at any terminal, and high speed operation is obtained at any terminal with sufficient current infeed to operate the local relays. Insufficient or no current infeed at one terminal means only that the protection at that end will not operate.

Each protective terminal of a blocking scheme has three basic units:

##### a. Fault detector 1 (FD1)

The basic functions of this unit are to detect faults behind the relay location and to initiate a signal to block the protection at the remote end. This unit should be as fast as possible, to avoid introducing any delay in the overall operating time of the scheme.

The relays used for this purpose have impedance or reverse offset mho characteristics in the impedance plane, as shown in Figure 13.14. Of the two, the impedance characteristic is generally preferred, since relays with this characteristic have a typical operating time of 1–5 ms, and are faster than offset mho relays, which have an operating time of 15–30 ms.

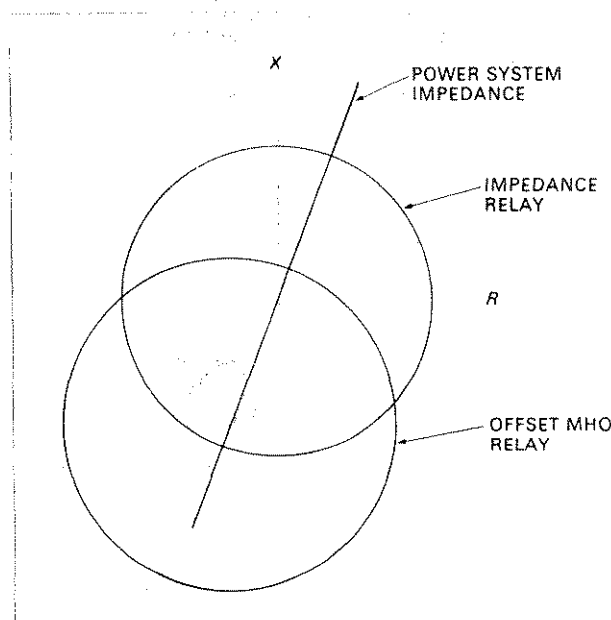


Figure 13.14 Characteristics of fault detectors for blocking schemes.

##### b. Directional unit (DU)

The function of this unit when it operates is to stop the blocking signal from the end at which it is located. Distance relays having a mho characteristic are normally used for the purpose.

### c. Fault detector 2 (FD2)

This unit will allow the protection to trip the local circuit breaker in the absence of a blocking signal.

The settings and sensitivities of the three units must meet the following conditions;

- i. The fault detector *FD1* must reach further in the reverse direction than the fault detectors *FD2* at the remote terminals. Case 3 of Table 13.2 is particularly relevant here.
- ii. The fault detector *FD2* should operate for any faults in the protected feeder, for high speed of operation. Otherwise, sequential fault clearance has to be accepted. Cases 1 and 2 in Table 13.2 should be considered when checking this point.

If sequential fault clearance is accepted, the forward reach of the fault detector *FD1* should not be greater than the forward reach of the fault detector *FD2* at the terminal which fails to see the fault initially. Otherwise, incorrect blocking of the protection will take place.

iii. The fault current may flow out of the feeder at one terminal when an internal fault occurs. This is case 4 in Table 13.2. The protective units at that terminal may see the fault as an external fault and send a blocking signal to the remote terminals, thereby preventing the correct operation of the scheme and clearance of the fault.

If this condition can occur, the only alternative is to supplement the blocking scheme with a direct intertrip scheme, using the independent zone 1 units of the distance scheme to initiate the intertrip signal.

iv. The setting of the directional unit should be such that no maloperation can occur for faults in the reverse direction; case 5 in Table 13.2.

### Signalling channel considerations

The minimum number of signalling channels required depends on the type of scheme used. With under-reach and blocking schemes only one frequency is required, whereas a permissive over-reach scheme requires as many frequencies as there are feeder ends. The signalling channel equipment at each terminal should include one transmitter and  $(N - 1)$  receivers, where  $N$  is the total number of feeder ends.

If frequency shift channels are used to improve the reliability of the protective schemes, mainly with transfer trip schemes,  $N$  additional frequencies are required for the purpose.

The problems of signal attenuation and impedance matching mentioned in Section 13.2.2 should also be carefully considered when power line carrier frequency channels are used.

### Directional comparison blocking schemes

The principle of operation of these schemes is the same as that of the distance blocking schemes described in the previous section. The difference lies in the type of unit used for the three functions mentioned in that section.

The fault detectors can be impedance relays or overcurrent and earth fault relays; directional phase and earth fault relays are utilized as the directional units.

The conditions to be checked are the same as for the distance blocking scheme. The main advantage of directional comparison schemes over distance schemes is their greater capability to detect high-resistance earth faults. The reliability of these schemes, in terms of stability for through faults, is lower than that of distance blocking schemes. However, with the increasing reliability of modern signalling channels, directional comparison blocking schemes seem to offer good solutions to the many and difficult problems encountered in the protection of multi-ended feeders.

## 13.2.5

### Differential Relay Using Optical Fibre Signalling

Current differential relays can provide unit protection for two-ended feeders or for multi-ended circuits without the restrictions associated with other forms of protection. Conventional current differential relays, however, require a continuous metallic pilot circuit between line ends for the communication of a.c. current signals.

In Section 8.4.5 the characteristics of optical fibre cables and their use in protection signalling are outlined. When they are used to provide signalling between relays at each end of a multi-ended circuit a novel current differential scheme, based on digital relaying techniques, can be implemented.

Such a three-ended system is shown in Figure 13.15, where the relays at each line end, illustrated in Figure 7.2, are digital relays interconnected by optical fibre links so that each can send information to the others. In practice the links can be dedicated to the protection system or multiplexed, in which case multiplexing equipment, not shown in Figure 13.15, will be used to terminate the cables.

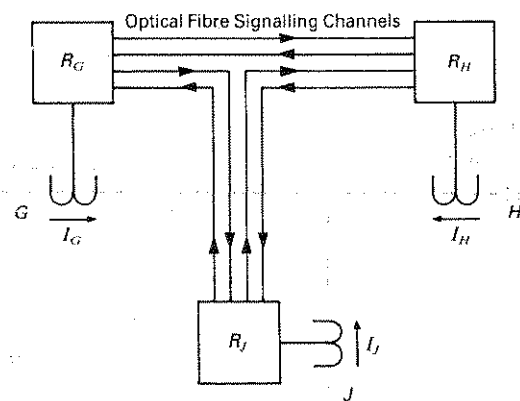


Figure 13.15 Current differential protection for tee'd feeders using optical fibre signalling.

If  $I_G$ ,  $I_H$ ,  $I_J$  are the current vector signals at line ends  $G$ ,  $H$ ,  $J$ , then for an unfaulted circuit:

$$I_G + I_H + I_J = 0$$

The basic principles of operation of the system are that each relay measures its local three phase currents and sends its values to the other relays. Each relay then calculates, for each phase, a resultant differential current and also a bias current, which is used to restrain the relay in the manner conventional for biased differential unit protection.

The bias feature is necessary in this scheme because it is designed to operate from conventional current transformers which are subject to transient transformation errors.

The two quantities are:

$$\begin{aligned} |I \text{ diff}| &= |I_G + I_H + I_J| \\ |I \text{ bias}| &= \frac{1}{2} (|I_G| + |I_H| + |I_J|) \end{aligned}$$

Figure 13.16 shows the percentage biased differential characteristic used, the tripping criteria being:

$$\begin{aligned} |I \text{ diff}| &> K |I \text{ bias}| \\ \text{and } |I \text{ diff}| &> I_S \end{aligned}$$

where  $K$  = percentage bias setting.  
 $I_S$  = minimum differential current setting.

### Operation

The three phase CT secondary currents at each line end



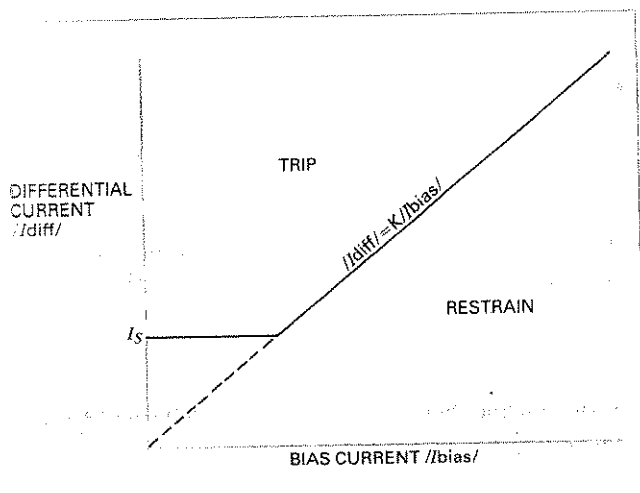


Figure 13.16 Percentage biased differential protection characteristic.

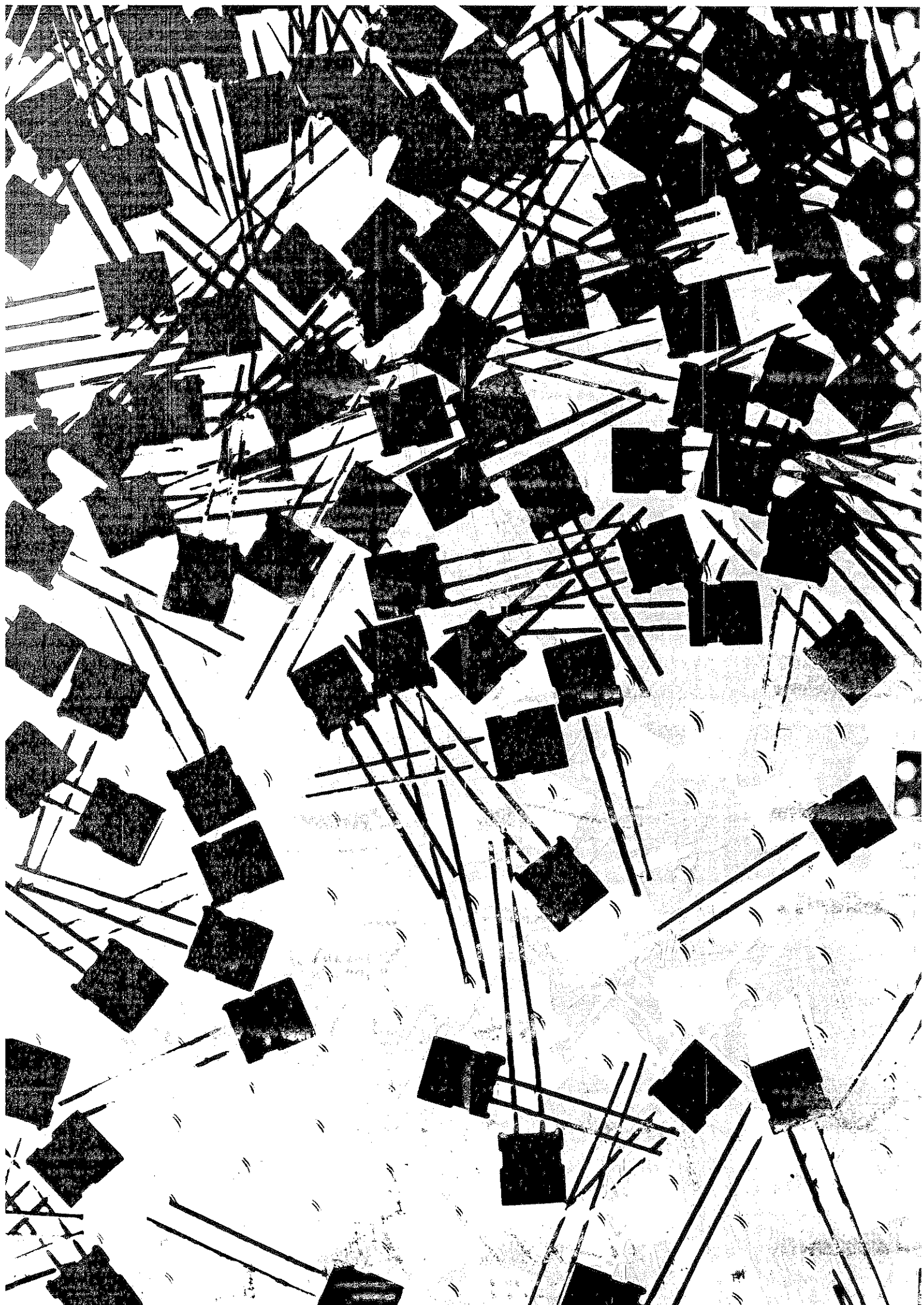
are fed to the respective relays where they are sampled at a fixed frequency and converted to digital form by an analog to digital converter. An associated microcomputer carries out signal processing algorithms to filter out unwanted d.c. and harmonic components. This process yields the power frequency components of the currents in vector form. The values obtained at each relay are transmitted to the others in a binary coded form, at the data rate of 64k bits/second, and each set of current samples transmitted is accompanied by error checking, status and synchronization data. The message frames are received in the relays which then carry out the calculations described above. If the magnitudes of the differential currents indicate that a fault has occurred the relays trip their local circuit breaker.

The relays also continuously monitor the communication channel performance and carry out self-testing and diagnostic operations.

The data samples obtained at each end of the line must be accurately time-aligned in order to realize effective synchronization when the relaying calculations are performed. This is achieved by a software-controlled 'poll and answer' technique by which the propagation delay of the communication channels is continuously measured. This is particularly important if the channels are part of a more general communications system.

Because the system uses individual phase currents, selective phase tripping can be used when required.

This biased differential protection is also applicable to plain feeders, having only two line ends, a factor which may be beneficial for transmission lines which are to be tee'd at a later date.



# Auto-reclosing

- 14.1
- 14.2
- 14.3
- 14.4
- 14.5
- 14.6
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- 14.8
- 14.9
- 14.10
- 14.11
- 14.12
- 14.13
- 14.14
- 14.15

## 14.1

An analysis of faults on any overhead line network operating at either high voltage (6–66kV) or extra-high voltage (110kV and above) has shown that 80–90% are transient in nature, the tendency being towards the lower percentage on high voltage (HV) networks and the higher figure on extra-high voltage (EHV) systems.

A transient fault, such as an insulator flash-over, is one which is cleared by the immediate tripping of one or more circuit breakers to isolate the fault, and which does not recur when the line is re-energized. Lightning is the most common cause of transient faults, other possible causes being swinging wires and temporary contact with foreign objects.

The remaining 10–20% of faults are either semi-permanent or permanent.

A semi-permanent fault could be caused by a small tree branch falling on the line. Here the cause of the fault would not be removed by the immediate tripping of the circuit, but could be burnt away during a time delayed trip. This type of fault is likely to be prevalent on HV lines traversing forest areas.

Permanent faults, such as broken conductors, and all faults on any sections of underground cable which may be included in the line, must be located and repaired before the supply can be restored.

This means that in the majority of fault incidents, if the faulty line is immediately tripped out, and time is allowed for the fault area to de-ionize, reclosure of the circuit breakers will result in the line being successfully re-energized.

Auto-reclose schemes are employed to carry out this duty automatically; they have been the cause of a substantial improvement in continuity of supply.

A further benefit, particularly to EHV systems, is the maintenance of system stability and synchronism.

Before discussing the problems involved in the application of auto-reclose schemes, it is useful to define some of the terms in common usage.

## 14.2

A number of the terms defined below are illustrated in Figure 14.1, which shows the sequence of events in a

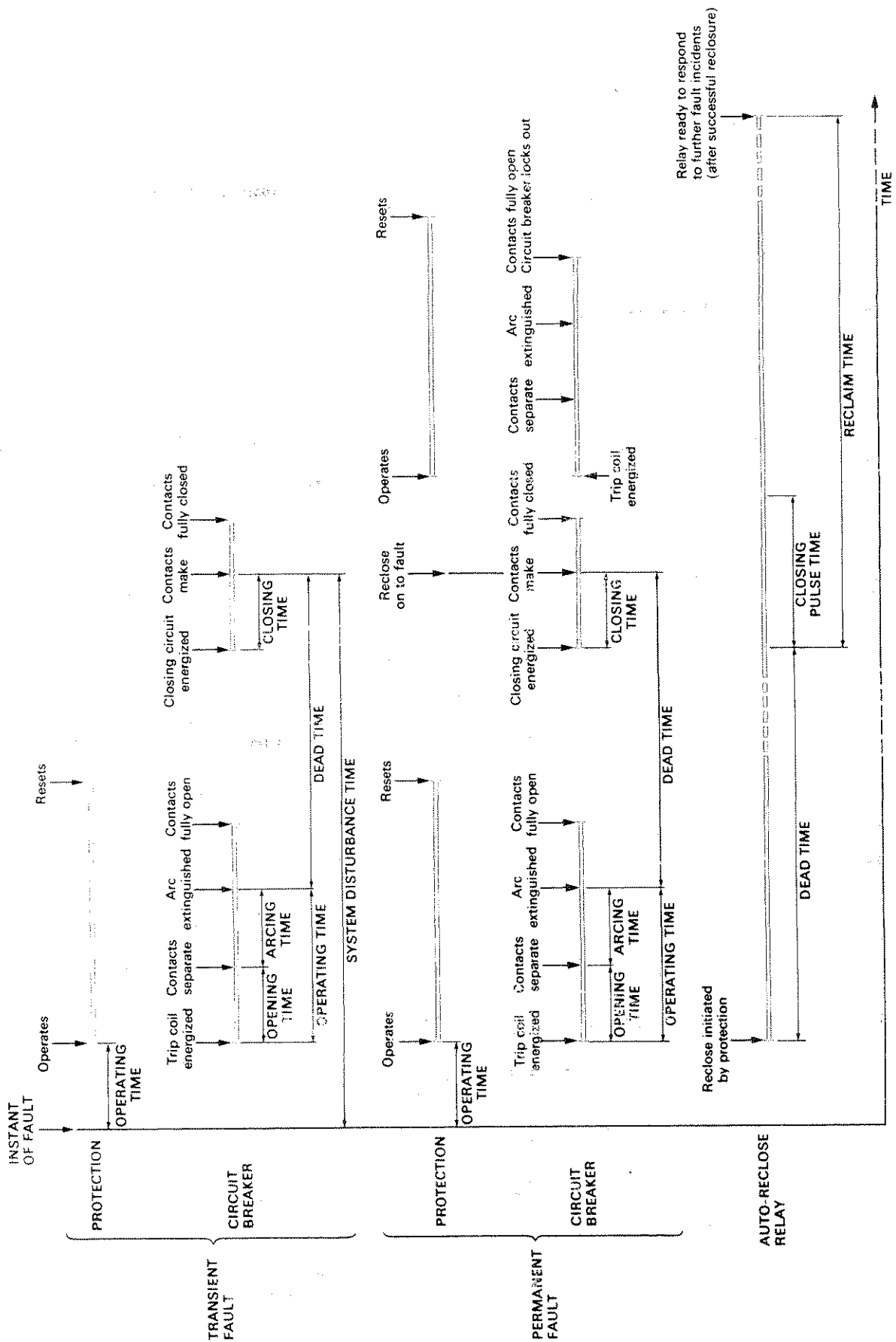


Figure 14.1 Operation of single-shot auto-reclose scheme for transient and permanent faults.

typical auto-reclose operation, where the circuit breaker makes one attempt at reclosure after tripping to clear a fault. Two conditions are shown; a successful reclosure in the event of the fault being transient, and an unsuccessful reclosure followed by lock-out of the circuit breaker if the fault is permanent.

#### **Anti-pumping**

A feature incorporated in the circuit breaker or reclosing scheme whereby, in the event of a permanent fault, repeated operations of the circuit breaker are prevented when the closing impulse lasts longer than the sum of the protective relay and circuit breaker operating times.

#### **Arcing time**

The time between the instant of separation of the circuit breaker contacts and the instant of extinction of the fault arc.

#### **Closing impulse time**

The time during which the closing contacts of the auto-reclose relay are made.

#### **Closing time**

The time from the energizing of the circuit breaker closing circuit to the making of the circuit breaker contacts.

#### **Counting relay**

A relay, usually of the electromechanical type, with a ratchet mechanism which is driven forward one step each time its coil is energized. A contact is operated after a chosen number of steps and the mechanism may be manually or electrically reset.

Often used to record the number of operations performed by a circuit breaker since last serviced or maintained, and to give an alarm and lock out on the expiry of the permitted number of fault operations between maintenance inspections.

A pre-lock-out alarm, indicating that lock-out will occur after the next reclosing operation, may also be provided.

#### **Dead time (auto-reclose relay)**

The time between the auto-reclose scheme being energized and the operation of the contacts which energize the circuit breaking closing circuit. On all but instantaneous or very high speed reclosing schemes, this time is virtually the same as the circuit breaker dead time.

#### **Dead time (circuit breaker or system)**

The time between the fault arc being extinguished and the circuit breaker contacts remaking.

#### **De-ionizing time**

The time following the extinction of an overhead line fault arc necessary to ensure dispersion of ionized air so that the arc will not re-strike when the line is re-energized.

#### **High speed reclosing scheme**

A scheme whereby a circuit breaker is automatically reclosed within 1 second after a fault trip operation.

#### **Lock-out**

A feature of an auto-reclose scheme which, after tripping of the circuit breaker, prevents further automatic reclosing.

#### **Low speed or delayed reclosing scheme**

A scheme whereby the automatic reclosing of a circuit breaker following a fault trip operation is delayed for a time in excess of 1 second.

#### **Multi-shot reclosing**

An operating sequence providing more than one reclosing operation on a given fault before lock-out of the circuit breaker occurs.

#### **Operation counter**

A counter, usually of the electromechanical cyclometer type, arranged to indicate the number of automatic operations, either closing or tripping, performed by a circuit breaker since its commissioning.

#### **Opening time**

The time between the energizing of the circuit breaker trip coil and the instant of separation of the contacts.

#### **Operating time (circuit breaker)**

The time from the energizing of the trip coil until the fault arc is extinguished.

#### **Operating time (protection)**

The time from the inception of the fault to the closing of the tripping contacts. Where a separate tripping relay is employed, its operating time is included.

#### **Reclaim time**

The time following a successful closing operation, measured from the instant the auto-reclose relay closing contacts make, which must elapse before the auto-reclose relay will initiate a reclosing sequence in the event of a further fault incident.

#### **System disturbance time**

The time between the inception of the fault and the circuit breaker contacts making on successful reclosing.

#### **Spring winding time**

On motor-wound spring-closed breakers, this is the time required for the motor to charge the spring fully after a closing operation.

#### **Single shot reclosing**

An operating sequence providing only one reclosing operation, lock-out of the circuit breaker occurring on subsequent tripping.

### **14.3**

#### **APPLICATION OF DEAD TIME**

The choice of dead time and reclaim time is of fundamental importance in the application of any auto-reclosing scheme. A further important decision to be made is whether to employ a single or multi-shot scheme. These decisions are influenced by the type of protection and switchgear employed, the nature of the system and the possibility of stability problems, and the effects on the various types of consumer loads. HV distribution networks and EHV transmission systems present different problems in this respect, and it is convenient to discuss them under separate headings. Sections 14.4, 14.5 and 14.6 deal with HV auto-reclosing while Sections 14.7 to 14.12 inclusive cover EHV schemes.

The rapid expansion in the use of auto-reclosing has led to the existence of a variety of different control schemes. The various features in common use are discussed in Section 14.13.

The application of static circuit techniques to auto-reclosing is dealt with in Section 14.14.

The related subject of auto-closing, that is, the automatic closing of normally open circuit breakers, is dealt with in Section 14.15.

On HV distribution networks, auto-reclosing is applied mainly to radial feeders where problems of system stability do not arise, and the main advantages to be derived from its use can be summarized as follows:

- a. Reduction to a minimum of the interruptions of supply to the consumer.
- b. Instantaneous fault clearance can be introduced, with the accompanying benefits of shorter fault duration, less fault damage, and fewer permanent faults.

As 80% of overhead line faults are transient, elimination of loss of supply from this cause by the introduction of auto-reclosing gives obvious benefits. Furthermore, auto-reclosing may allow a particular substation to be run unattended, saving the wages of personnel. In the case of unattended substations, the number of visits by personnel to reclose a circuit breaker manually after a fault can be substantially reduced, an important consideration for substations in remote areas.

The introduction of auto-reclosing gives an important benefit on circuits using time graded protection, in that it allows the use of instantaneous protection to give a high speed first trip. With fast tripping, the duration of the power arc resulting from an overhead line fault is reduced to a minimum, thus lessening the chance of damage to the line, which might otherwise cause a transient fault to develop into a permanent fault. The application of instantaneous protection, however, could result in non-selective tripping of a number of circuit breakers and an ensuing loss of supply to a number of unfaulted sections. Auto-reclosing allows all these circuit breakers to be reclosed within a few seconds; with transient faults the overall effect would be loss of supply for a very short time but affecting a larger number of consumers. If time graded protection alone were used, a smaller number of consumers might be affected, but for a considerable time and with less chance of a successful reclosure.

It should be noted that when instantaneous protection is used with auto-reclosing, the scheme is normally arranged to isolate the instantaneous protection after the first trip, so that, if the fault persists after reclosure, the time graded protection will give discriminative tripping, resulting in the isolation of the faulted section.

Some schemes allow a number of reclosures and time graded trips after the first instantaneous trip, which may result in the burning out and clearance of semi-permanent faults.

A further benefit of instantaneous tripping is a reduction in circuit breaker maintenance by eliminating pre-arc heating when clearing transient faults.

When considering feeders which are partly overhead line and partly underground cable, any decision to install auto-reclosing would be influenced by any data known on the frequency of transient faults. When a significant proportion of faults is permanent, the advantages of auto-reclosing are small, particularly since reclosing on to a faulty cable is likely to aggravate the damage.

## 14.5

The factors which influence the choice of dead time, reclaim time and the number of shots are now discussed.

### 14.5.1

#### Dead time

#### *System stability and synchronism*

As stated in the previous section, the questions of stability

and synchronism are not met on radial feeders. However there are isolated situations on HV systems in which such considerations could arise, and the subject is mentioned here briefly for the sake of completeness. The matter is dealt with more fully in Sections 14.7 and 14.8 on EHV systems.

The problem arises only on networks with more than one power source, where power can be fed into both ends of an inter-connecting line. An example is a factory which runs its own generating plant in synchronism with the local supply network. Another example could arise in a sparsely populated area, where a small centre of population with diesel generating plant may be connected to the rest of the supply system by a single tie-line.

In order to reclose without loss of synchronism after a fault on the interconnecting feeder, the dead time must be kept to the minimum permissible to allow de-ionization of the fault arc, and other time delays which contribute to the total system disturbance time must be kept as short as possible.

The use of high speed protection, such as pilot wire or distance schemes, with operating times of the order of 50 milliseconds is essential. The circuit breakers must be capable of interrupting the fault current in a further 50–100 milliseconds, and then reclosing the circuit after a dead time of the order of 0.2–0.3 s.

Fault arc de-ionization time is reduced by rapid fault clearance, a further benefit derived from high speed protection and fast operating circuit breakers, and on HV systems a dead time of 0.1–0.2 s should be enough to achieve de-ionization.

Only the most modern HV circuit breakers are likely to be suitable for this high speed reclosing duty; more information on this matter may be found in the section on circuit breaker characteristics, below.

It may be desirable in some cases to fit a synchronism check relay, so that auto-reclosing is prevented if the phase angle has moved outside a certain chosen limit.

On HV systems, the main problem to be considered in relation to dead time is the effect on various types of consumer load.

#### *i. Industrial consumers.*

An important point here is the effect of dead time on the operation of synchronous motors and induction motors. The duration of an interruption in supply which a synchronous motor can tolerate without loss of synchronism is dependent on the inertia of the motor and its load, but is likely to be extremely short. In practice it is therefore desirable to disconnect the motor from the supply in the event of a fault; the dead time should be sufficient to allow the motor no-volt trip feature to operate.

Induction motors, on the other hand, can be allowed to coast through the supply interruption, subject to certain precautions.

A minimum dead time of 0.3 s has been suggested to allow synchronous motor no-volt trips to operate, and a maximum of 0.5 s for satisfactory induction motor coasting. A dead time of 0.4 s would therefore appear to be a suitable choice, and has in fact been tried with some success.

There are snags to this practice however, and it should be attempted only with a full knowledge of all the motor control gear, motor characteristics and load conditions. The major difficulties are caused by wide variations in load causing tripping of some motors and others to continue to run, giving rise to dangerous or damaging conditions in process plant.

A point to be watched in connection with induction motors is that voltage is generated for a short time after the removal of the supply; if the supply is reconnected during this period, there is a danger of a large phase angle

difference which could result in mechanical damage or insulation breakdown.

For this reason time should be allowed for this voltage to decay before reconnection of the supply, and, where coasting is desired, arrangements must be made to ensure that the starter does not isolate the motor from the supply terminals.

In the general case, dead times of 3–10 s, which allow all motors to be disconnected, are normally satisfactory, but there may be special cases, such as a large works or colliery, for which additional time is required to permit the resetting of manual controls and safety devices.

## ii. Street lighting

Street lighting is a load which demands special attention, particularly in these days of busy roads and fast moving traffic. Obviously the shorter the time the lights are out the better. Intervals of 10 seconds or more are very dangerous, as they demand the use of headlights and an immediate reduction in speed to suit the new visibility conditions. Intervals of 1 or 2 seconds are usually satisfactory, as the lighting will then be restored before normal reaction times would allow any action to be attempted, and it is unlikely that any dangerous conditions will have arisen during this short time.

## iii. Domestic consumers

It is improbable that expensive processes or dangerous conditions will be involved with domestic consumers and the main consideration is that of inconvenience. This is mainly a justification for auto-reclosing, as a dead time of seconds or minutes is of little importance compared with the spoiled meals, cold fires and missed television programmes resulting from hours of supply failure that would occur without auto-reclosing. Television sets have some bearing on this matter, as it is recommended that if they cannot be switched on again inside 10 seconds they should be left for 2 or 3 minutes. This gives a time limit of 10 seconds; inside this time limit very little inconvenience will be suffered by domestic consumers. The only remaining consideration is that, from the point of view of the supply authority, the dead time should be shorter than the time required for an irate consumer to get to the telephone to make a complaint.

## Circuit breaker characteristics

Oil circuit breakers are in common use on HV systems, and may be fitted with solenoid, hand-wound spring or motor-wound spring closing mechanisms. The hand-wound spring type has limited appeal for auto-reclosing duty, since manual rewinding is required after each reclosure. Solenoid and motor-wound spring operated breakers can perform repeated auto-reclose sequences without manual attention.

The time delays imposed by the circuit breaker during a tripping and reclosing operation must be taken into consideration, especially when assessing the possibility of applying high speed auto-reclosing.

### a. Operating time

As the fault may result in a collapse of system voltage, the effective dead time can be increased by the circuit breaker operating time. With modern circuit breakers, this time is usually in the range 50–100 ms, but could be longer with older designs.

### b. Mechanism resetting time

Most circuit breakers are 'trip free', which means that the breaker can be tripped during the closing stroke. Closing is carried out via a system of toggle links which collapse under a tripping impulse. After tripping, time must be allowed for this mechanism to reset before applying a closing impulse. The resetting time may be of the order of 0.2 s and, where high speed reclosing is required, a latch check switch is desirable. This switch, used as an interlock

in the reclosing circuit, makes only when the closing mechanism is fully latched to the main contacts.

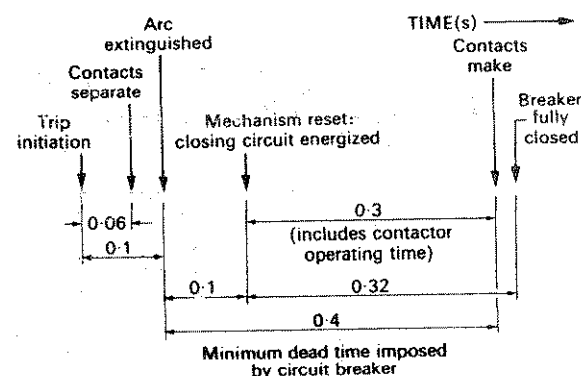
### c. Closing time

This is the time interval between the energization of the closing mechanism and the making of the contacts. Owing to the time constant of the solenoid and the inertia of the plunger, a solenoid closing mechanism may take 0.3 s. A spring operated breaker, on the other hand, can close in less than 0.2 s.

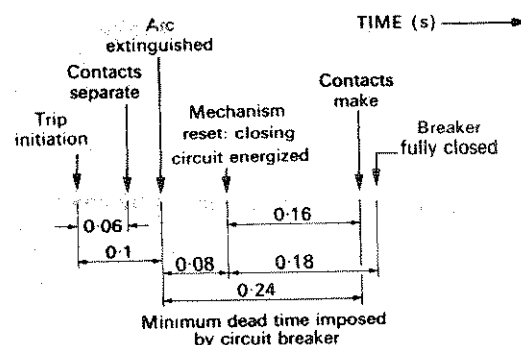
### d. Clearing of arc products

It has been generally considered that a major limitation to the application of HV oil circuit breakers to high speed reclosing is the time necessary for the circuit breaker arc control devices to clear themselves of ionized gas, burnt oil and so on, and to recover their full oil content, in order to be in a fit state to reclose on to a possible permanent fault. Tests have shown, however, that this limitation is not as serious as was previously considered, since satisfactory breaking characteristics can be obtained even when the arcing chambers have not fully recovered their oil content.

The circuit breaker mechanism imposes a minimum dead time made up from the sum of (b) and (c) above, while the effective minimum dead time may in practice be increased by the operating time, discussed in (a). The time for the clearance of arc products, from (d), is disregarded as insignificant compared to the sum of mechanism resetting and closing times. Figure 14.2 illustrates the performance of modern 11kV circuit breakers in this respect, both solenoid and spring closed types. Older circuit breakers may give longer times than those shown, and it will be appreciated that solenoid closed breakers are in many cases unsuitable for high speed auto-reclosing.



(a) 11kV SOLENOID-CLOSED CIRCUIT BREAKER



(b) 11kV SPRING-CLOSED CIRCUIT BREAKER

### NOTE

The above diagrams assume the application of the closing pulse immediately the breaker mechanism resets after tripping

Figure 14.2 Performance of modern 11kV circuit breakers.

## De-ionization of fault path

As mentioned in the above paragraph on system stability and synchronism, successful high speed reclosure requires

the interruption of the fault by the circuit breaker to be followed by a time delay long enough to allow the ionized air to disperse. This time is dependent on the system voltage, cause of fault, weather conditions and so on, but at voltages up to 66kV 0.1–0.2 s should be adequate. On HV systems, therefore, fault de-ionization time is of less importance than circuit breaker time delays. This is not always the case on EHV systems however, and the matter is dealt with more fully later in Section 14.8.2.

#### **Protection reset time**

If time delayed protection is used, it is essential that the timing device shall fully reset during the dead time, so that correct time discrimination will be maintained after reclosure on to a fault. The reset time of the electromechanical I.D.M.T. relay is 10 seconds or more when on maximum time setting, and dead times of at least this value must be chosen.

When short dead times are required, the protective relays must reset instantaneously, a requirement with which static I.D.M.T. relays can easily comply.

#### **14.5.2**

##### **Reclaim time**

##### **Types of protection**

The reclaim time must be long enough to allow the protective relays to operate when the circuit breaker is reclosed on to a permanent fault. The most common forms of protection on HV lines are I.D.M.T. or definite time over-current and earth fault relays.

The maximum operating time for the former with very low fault levels is about 30 seconds, while for fault levels of several times rating the operating time may be 10 seconds or less.

In the case of definite time protection, settings of 3 seconds or less are common, with 10 seconds as an absolute maximum. It has been common practice to use reclaim times of 30 seconds on HV auto-reclose schemes, but the danger with a setting of this length is that during a thunderstorm when the incidence of transient faults is high, the breaker may reclose successfully after one fault, and then trip and lock out for a second fault occurring, say 20 seconds later. With a reclaim time reduced to 15 seconds, the second fault would have been treated as a separate incident with a further successful reclosure.

Where fault levels are low, it may be difficult to select I.D.M.T. time settings to give satisfactory grading with an operating limit of 15 seconds, and the matter becomes a question of selecting a reclaim time compatible with I.D.M.T. requirements.

It is becoming increasingly common to fit sensitive earth fault protection to supplement the normal protection in order to detect high resistance earth faults. This protection cannot possibly be stable on through faults, and is therefore set to have an operating time longer than that of the main protection. This longer time may have to be taken into consideration when deciding on a reclaim time, but it must be borne in mind that this type of fault, for example a broken overhead conductor in contact with dry ground or a wood fence, is rarely if ever transient and may be a danger to the public. It is therefore common practice to use a contact on the sensitive earth fault relay to block auto-reclosing and lock out the circuit breaker.

Where high speed protection is used, reclaim times of 1 second or less would be adequate. However, such short times are rarely used in practice, to relieve the duty of the circuit breaker.

##### **Spring winding time**

Where motor-wound spring closed breakers are used, the reclaim time must be at least as long as the spring winding

time, to ensure that the breaker is not subjected to a further reclosing operation with a partly wound spring. Spring winding times of 30 seconds or more are common and since this time is longer than the protective relay operating time, it is possible to simplify the auto-reclose relay by using the spring winding mechanism as the reclaim device.

Some modern breakers, however, have winding times as low as 3 seconds, and in such cases separate reclaim timers must be used.

#### **14.5.3**

##### **Number of shots**

There are no clear-cut rules for defining the number of shots for any particular application, but a number of factors must be taken into account.

##### **a. Circuit breaker limitations**

Important considerations are the ability of the circuit breaker to perform several trip and close operations in quick succession and the effect of these operations on the maintenance period. Maintenance is usually required after between 5 and 20 trips, depending on the fault level.

The fact that 80% of faults are transient shows the advantage of single shot schemes, as these give the maximum maintenance period with considerable benefit from auto-reclosing.

##### **b. System conditions**

If statistical information on a particular system shows a moderate percentage of semi-permanent faults which could be burned out, a multi-shot scheme may be justified. This is often the case in forest areas.

Again, if fused 'tees' are used and the fault level is low, the fusing time may not discriminate with the main I.D.M.T. relay and it would then be useful to have several shots. This would warm up the fuse to such an extent that it would eventually blow before the main protection operated.

##### **c. Vacuum circuit breakers**

The vacuum circuit breaker has the important advantage of being virtually maintenance-free. Its application to HV systems was limited initially by its greater cost as compared with the oil circuit breaker, but this objection is being overcome, so multi-shot auto-reclose schemes are enjoying greater popularity.

#### **14.6**

##### **AUTOMATIC RECLOSERS**

These are small automatic pole-mounted circuit breakers suitable for connecting directly in the line. The contacts are normally held closed by a spring, being opened by a series solenoid. No auxiliary supply is required, as the mechanism is operated by the fault energy. One type in common use incorporates a timing device which gives an operating cycle of two instantaneous trips followed by two delayed trips with an interval, that is, dead time, of approximately one second between each trip and reclosure. The main contacts will remain closed and the mechanism will return to normal should the fault be cleared during this cycle. If the fault is permanent, the contact will be locked out at the end of the cycle and must be reclosed by hand.

Reclosers may be single or three phase units. When any single phase unit locks out after completing the cycle, the other two are also tripped and locked out.

Reclosers are commonly used on rural lines with fused spurs and sections. The instantaneous tripping times are made as fast as possible, so that the fuses will not blow and minimum deterioration to the fuse is caused on the occurrence of a fault. In addition, high speed clearance increases the chance of the fault being transient. Should this be so, the contacts will remain closed and the mechanism reset to normal. Should the fault be permanent, a time delayed trip follows, which will allow the fuse on the faulted spur or section to blow. A second time delayed trip is provided in



order to assist co-ordination with the fuses at low fault levels by pre-heating the fuse. Should the fault be on the main line, the recloser will trip again and lock out.

For the higher levels of current the steepness of the fuse characteristic may mean that optimum discrimination between a fuse and a recloser is not attainable solely by co-ordinating dependent time characteristics. It is in these circumstances that an automatic sectionalizer, with its ability to count the passages of fault current, can provide the optimum solution, as described in Section 14.6.1.

Reclosers can also be used for line sectionalizing purposes when operated in series with circuit breakers fitted with single shot auto-reclose schemes giving one instantaneous trip followed by a time delayed trip. On the passage of current to a fault beyond the recloser, both the circuit breaker and recloser will perform high speed trips. The line will be re-energized when the circuit breaker has been reclosed; further tripping of the circuit breaker is controlled by the I.D.M.T. relay. If the recloser is arranged to provide high speed tripping throughout its operating sequence, these operations will occur within the inverse tripping time of the circuit breaker; the recloser will therefore lock out, isolating only the faulty section, while the circuit breaker remains closed.

If the recloser has one or more delayed trips, the settings of the circuit breaker I.D.M.T. relay must be co-ordinated with the recloser tripping time. When the recloser remakes the circuit after a delayed trip, an electromechanical I.D.M.T. relay may not have time to reset to zero before being re-energized either by the persistence of the original fault or the occurrence of a second one. Allowance must be made for this to ensure correct discrimination.

The advantage of reclosers is their low cost compared with circuit breakers with auto-reclose schemes. Their limitation

is their breaking capacity, the largest available units having a fault rating of 125 MVA at 11 kV or 250 MVA at 22 kV.

#### 14.6.1

##### Automatic sectionalizers

Overhead distribution systems such as those rated at 11kV have been liable to widespread interruption of the supply even when automatic reclosers are in service.

This is because the fuses which have been commonly applied to the spurs of such systems have been inherently unable to provide adequate protection without also blowing unnecessarily for some transient, non-damaging faults.

This problem can now be avoided by the advent of an automatic sectionalizer which can be used directly in place of 11kV fuses, as shown in Figure 14.3, to improve discrimination and so reduce supply loss periods.

The automatic sectionalizer type CETS, illustrated in Figure 14.4, uses electronic circuitry to monitor the current flow in the spur via an inbuilt CT. It discriminates between a transient fault and a persistent fault by counting the passages of fault current. During the dead time following the second passage of fault current due to a persistent fault, a chemical actuator is energized to eject a driving pin, the force of which unlatches the sectionalizer arm, isolating the spur. The CETS remains in this condition until the charge is replaced and the arm reset.

The electronic circuitry is mounted on a specially designed printed circuit board sealed into and electrically shielded by the operating arm, on which the current transformer is also mounted.

Disconnection during the dead time between reclosure attempts eliminates arcing and any resultant fire risk, noise and contact damage. The sectionalizer is immune to trans-

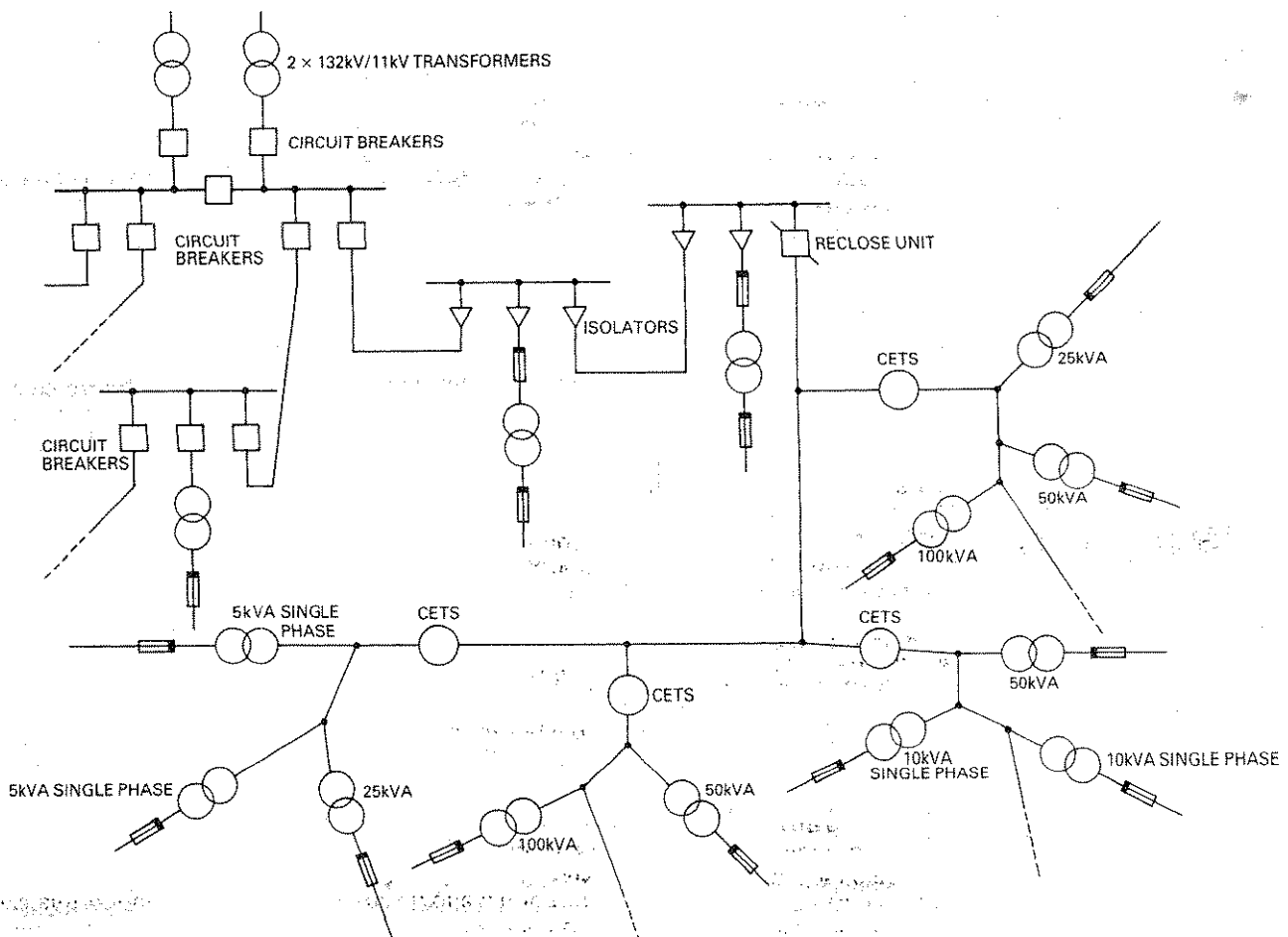


Figure 14.3 Application of automatic sectionalizers to an 11kV distribution network.

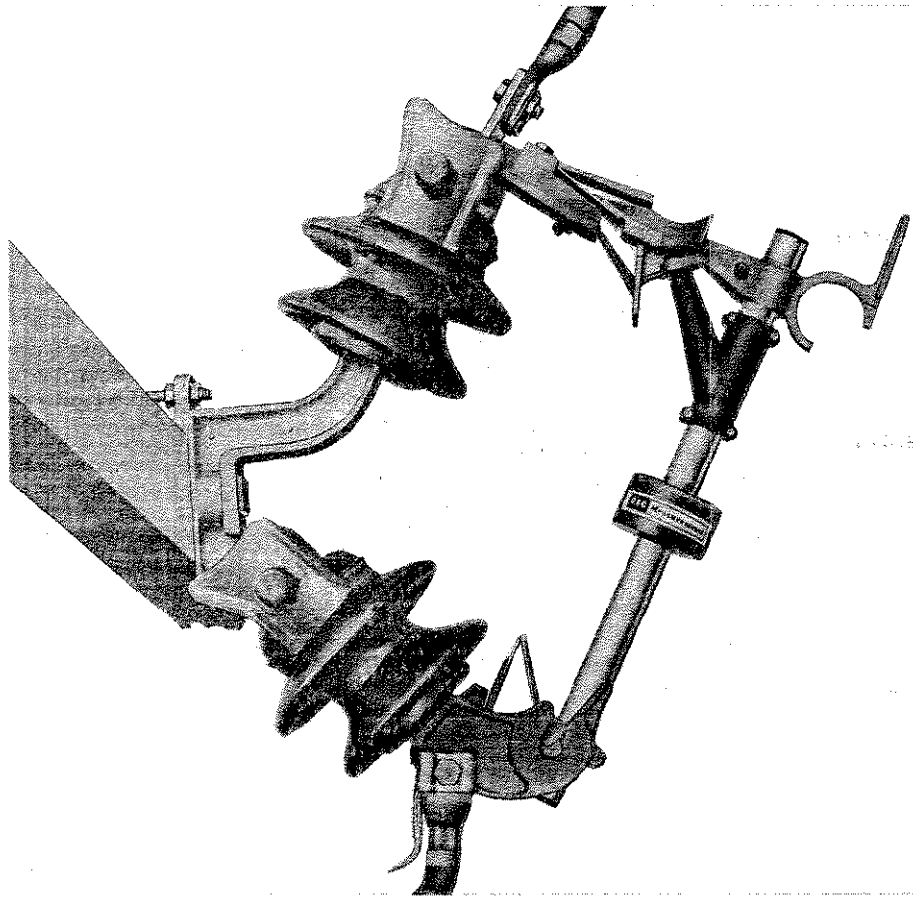


Figure 14.4 Automatic sectionalizer, type CETS, for a single phase.

former inrush and no deterioration of operating characteristics occurs due to fault current.

The CETS is manufactured by GEC ALSTHOM Measurements under a licence agreement with the UK Electricity Council.

#### 14.7

On EHV transmission lines, the most important consideration in the application of auto-reclosing is the maintenance of system stability and synchronism. The problems involved are dependent on whether the transmission system is a loosely connected one, in which, for instance, two power systems may be connected by a single tie-line, or, alternatively, highly interconnected, such as the C.E.G.B. transmission network in the U.K.

An illustration is the interconnector between two power systems as shown in Figure 14.5. Under healthy conditions, the amount of synchronizing power transmitted,  $P$ , crosses the power/angle curve  $OAB$  at point  $X$ , showing that the phase displacement between the two systems is  $\theta_0$ . Under fault conditions, the curve  $OCB$  is applicable, and the operating point changes to  $Y$ . Assuming constant mechanical input to the machines, there is now an accelerating power  $XY$ . As a result, the operating point moves to  $Z$ , with an increased phase displacement,  $\theta_1$ , between the two systems, at which point the circuit breakers trip and break the connection. The phase displacement continues to increase at a rate dependent on the inertia of the two power sources; to maintain synchronism the breaker must be reclosed in a time short enough to prevent the phase angle exceeding  $\theta_2$ . This angle is such that the area (2) stays greater than the area (1), which is the condition for maintenance of synchronism.

This example shows that the successful application of auto-reclosing in such a case needs high speed protection, fast operating circuit breakers and a short dead time.

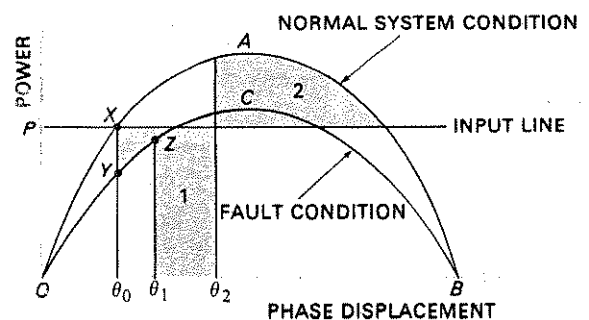
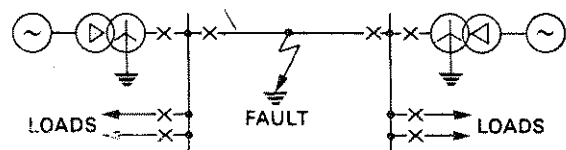


Figure 14.5 Effect of high speed three-phase auto-reclosing on system stability.

On highly interconnected systems, on the other hand, synchronism is unlikely to be lost by the tripping out of a single line. Here the best policy may be to adopt low speed, or delayed, auto-reclosing, in order that power swings on the system resulting from the fault may have time to settle down before reclosure is attempted. This is the policy adopted by the C.E.G.B.

The various factors to be considered when using EHV auto-reclose schemes are now dealt with. High speed and delayed schemes are discussed separately.

## 14.8

The first requirement for the application of high speed auto-reclosing is a knowledge of the system disturbance time that can be tolerated without loss of system stability. The power/phase angle curve of Figure 14.5, together with the value of electrical power transmitted, allows the permissible load angle change to be estimated. It will then be necessary to have some knowledge of the load angle change/time relationship in order to estimate the maximum permissible system disturbance time. A knowledge of protection and circuit breaker operating characteristics and fault arc de-ionization times is necessary to assess the feasibility of high speed auto-reclosing in any given case. These factors are now discussed.

### 14.8.1

#### Protection characteristics

The use of high speed protective gear, such as distance or pilot wire schemes, giving operating times of the order of 50 ms, is essential. In conjunction with fast operating circuit breakers, high speed protection reduces the duration of the fault arc and thus the total system disturbance time.

It is important that the circuit breakers at both ends of a faulty line should be tripped simultaneously. Any time during which one circuit breaker is open in advance of the other represents an effective reduction in the dead time, and may well jeopardize the chances of a successful reclosure. When distance protection is used, and the fault occurs near one end of the line, special measures have to be adopted to ensure simultaneous tripping at each end. These are described in Section 14.10.

### 14.8.2

#### De-ionization of fault path

When using high speed auto-reclosing, it is important to know the time for which a line must be de-energized in order to allow complete de-ionization of the arc, so that it will not restrike when the voltage is re-applied.

The de-ionization time of an uncontrolled arc in free air depends on the circuit voltage, conductor spacing, fault currents, fault duration, wind speed and capacitive coupling from adjacent conductors. Of these, the circuit voltage is the most important, and as a general rule, the higher the voltage the longer the time required for de-ionization.

Typical values are as follows:

| Transmission line voltage (kV) | Minimum de-energization time (seconds) |
|--------------------------------|----------------------------------------|
| 66                             | 0.1                                    |
| 110                            | 0.15                                   |
| 132                            | 0.17                                   |
| 220                            | 0.28                                   |
| 275                            | 0.3                                    |
| 400                            | 0.5                                    |

If single-phase tripping and auto-reclosing is used, especially on long transmission lines, the faulty phase should be disconnected for a longer time interval than in the case of three-phase tripping and auto-reclosing, in order to obtain an equal probability of successful reclosure. The reason for this is that, while the faulty phase is open, capacitive coupling between the healthy phases tends to maintain the arc.

### 14.8.3

#### Circuit breaker characteristics

With the large concentration of electrical power and high fault levels involved on EHV systems, the high speed auto-reclose cycle imposes a very severe duty on the per-

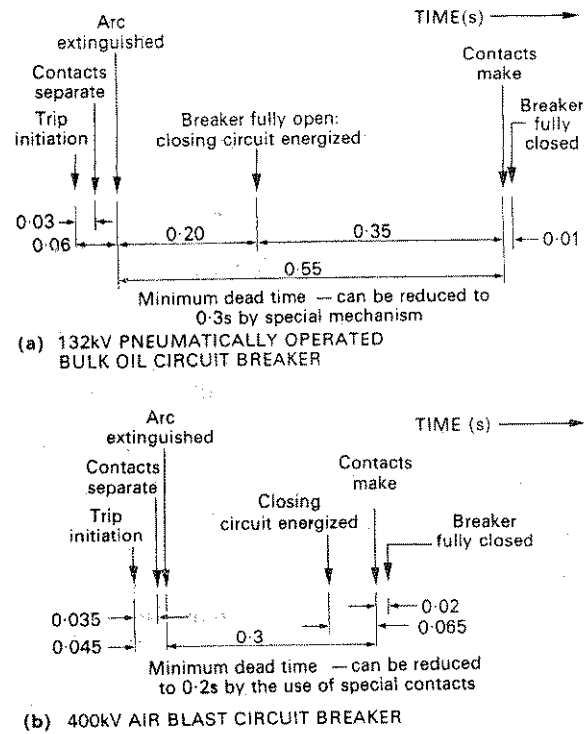


Figure 14.6 Typical circuit breaker trip-close operations.

formance of circuit breakers. The accepted breaker cycle of break-make-break requires the circuit breaker to interrupt the fault current, reclose the circuit after a time delay of 0.2s upwards and then break the fault current again if the fault persists.

The types of circuit breaker commonly used on EHV systems are oil, air blast and SF<sub>6</sub> types.

#### Oil circuit breakers

Used for transmission voltages up to 300kV, oil circuit breakers can be subdivided into the two types 'bulk oil' and 'small oil volume'. The latter is a design aimed at reducing the fire hazard associated with the large volume of oil contained in the 'bulk oil' breaker.

The operating mechanisms of oil circuit breakers are of two types, 'fixed trip' and 'trip free', of which the latter is the most common. The trip free mechanism consists of a collapsible link arrangement which can trip the breaker even when the normal closing pulse has been applied. With this mechanism, the reclosing cycle must allow time for the collapsible links to reset after tripping before applying the closing impulse.

The mass of the moving parts in EHV oil circuit breakers is such that special means have to be adopted to obtain the short dead times required for high speed auto-reclosing. One method is to use a fixed trip mechanism, in which the operating unit is solidly linked to the moving contacts, and to reverse the travel of the contacts before the opening stroke has been completed. The danger here is the possibility of reclosing before the arc is properly extinguished.

Another solution is to use a special trip free mechanism which allows the moving contacts to complete half their normal travel on tripping, thus ensuring arc extinction, and then applies the closing impulse to reclose the breaker. The trip free feature is retained throughout.

The three types of closing mechanism fitted to oil circuit breakers are solenoid, spring and pneumatic. Solenoid closing is not much used on EHV breakers owing to the high battery capacity needed; for example 300A or more at 110V d.c. is typical for a three-phase 132kV breaker. Also,

the high time constant of the solenoid makes it unsuitable for high speed reclosing.

Spring mechanisms are generally limited to breakers up to 66kV, but have been employed up to 132kV.

Pneumatic closing mechanisms can be said to be universal at the upper end of the EHV range and give the fastest closing time.

Figure 14.6(a) shows a trip-close operation for a pneumatically operated 132kV breaker, showing the dead time which can be attained with and without the special high speed reclosing mechanism.

#### **Air blast circuit breakers**

Air blast breakers have been developed for voltages up to the highest at present in use on transmission lines. They fall into two categories:

##### **a. Pressurized head breakers**

Compressed air is maintained in the chamber surrounding the main contacts. When a tripping signal is received, an auxiliary air system separates the main contacts and allows compressed air to blast through the gap to the atmosphere, extinguishing the arc. With the contacts fully open, compressed air is maintained in the chamber. Some types of breaker maintain the contacts open by air pressure, others by a mechanical latch.

Loss of air pressure could result in the contacts reclosing, or, if a mechanical latch is employed, restriking of the arc in the de-pressurized chamber.

For this reason, sequential series isolators, which isolate the main contacts after tripping, are commonly used with air blast breakers. Since these are comparatively slow in opening, their operation must be inhibited when auto-reclosing is required. A contact on the auto-reclose relay is made available for this purpose.

##### **b. Non-pressurized head breakers**

The chamber surrounding the main interruptors is non-pressurized, compressed air being contained in a separate chamber at the base of the circuit breaker housing. The operating times are longer than those of the pressurized type, owing to the delay involved in the flow of air from the chamber to the main contacts. For this reason non-pressurized head breakers have largely been superseded by the pressurized type.

Operating times for typical 400kV pressurized head air blast breakers are given in Figure 14.6(b).

#### **SF<sub>6</sub> circuit breakers**

Most EHV circuit breaker designs now being manufactured use SF<sub>6</sub> gas instead of compressed air as an insulating and arc quenching medium. The basic design of such circuit breakers is in many ways similar to that of pressurized head air blast circuit breakers, and they have similar operating characteristics.

SF<sub>6</sub> circuit breakers operate at much lower gas pressures than do air blast circuit breakers, and normally retain all, or almost all, of their voltage withstand capability, even if the SF<sub>6</sub> pressure level falls to atmospheric pressure. Sequential series isolators are therefore not normally used, but they are sometimes specified to prevent damage to the circuit breaker in the event of a lightning strike on an open ended conductor. Provision should therefore be made to inhibit sequential series isolation during an auto-reclose cycle.

#### **14.8.4**

##### **Choice of dead time**

Figures 14.6(a) and 14.6(b) illustrate the performance of typical oil and air blast EHV breakers and give the minimum dead times imposed by the circuit breaker operating characteristics. Reference to the table in Section 14.8.2 shows that, at voltages of 220kV and above, the de-ioniza-

tion time, rather than any circuit breaker limitations, will probably dictate the minimum dead time. The dead time setting on a high speed auto-reclose relay should be long enough to ensure complete de-ionization of the arc. On EHV systems, an unsuccessful reclosure is more detrimental to the system than no reclosure at all.

#### **14.8.5**

##### **Choice of reclaim time**

Where EHV oil circuit breakers are concerned, the reclaim time should take account of the time needed for the closing mechanism to reset ready for the next reclosing operation. For example, pneumatically operated breakers require time for the closing piston to return to its normal position, a process which can take up to 10 seconds. Spring closed breakers may require up to 30 seconds rewinding time before further reclosures can be undertaken.

The reclaim time for air blast breakers must allow time for the air pressure to recover to its normal value.

The reclaim time for SF<sub>6</sub> breakers must allow time for the operating mechanism (usually hydraulic) to recharge, and, in some designs ('two pressure' types), for the high pressure SF<sub>6</sub> reservoir to recharge.

#### **14.8.6**

##### **Number of shots**

High speed auto-reclosing on EHV systems is invariably single shot. Repeated reclosure attempts with high fault levels would have serious effects on system stability, so the circuit breakers are locked out after one unsuccessful attempt.

Furthermore, the incidence of semi-permanent faults which can be cleared by repeated reclosures is likely to be less than on HV systems.

#### **14.9**

##### **THREE-PHASE VERSUS SINGLE-PHASE AUTO-RECLOSEING**

When three-phase auto-reclosing is applied to single circuit interconnectors between two power systems, the tripping of all three phases on a fault causes an immediate drift apart of the two systems in their phase relation to one another, as described in Section 14.7. No interchange of synchronizing power can take place during the dead time.

If, on the other hand, only the faulty phase is tripped during earth fault conditions, which account for the vast majority of faults on overhead lines, synchronizing power can still be interchanged through the healthy phases.

For single-phase auto-reclosing each phase of the circuit breaker must be segregated and provided with its own closing and tripping mechanism; this is normal with EHV air blast and SF<sub>6</sub> breakers and most oil breakers.

The associated tripping and reclosing circuitry is therefore more complicated, and, except in distance schemes, the protection needs the addition of phase selecting relays. It is normal practice to arrange that, in the event of multi-phase faults, all three phases of the circuit breaker are tripped and locked out.

The advantages of single-phase auto-reclosing are the maintenance of transfer of synchronizing power, and, on multiple earth systems, negligible interference with the transmission of load. This is because the open phase current can flow through earth via the various earthing points until the fault is cleared and the faulty phase restored.

The main disadvantage is the longer de-ionization time resulting from capacitive coupling between the faulty and healthy lines, which can cause interference with communication circuits, and in certain cases, maloperation of earth fault relays on double circuit lines owing to the flow of zero sequence currents. These are induced by mutual induction between faulty and healthy lines.

## 14.10 HIGH-SPEED AUTO-RECLOSING ON LINES EMPLOYING DISTANCE SCHEMES

The importance of simultaneous tripping of the circuit breakers at each end of a faulted line where high speed auto-reclosing is employed has already been stressed, in Section 14.8.1. Distance protection imposes some difficulties in this respect.

Owing to the errors involved in determining the ohmic setting of the distance relays, it is not possible to set a distance relay to cover 100% of the protected line with any hope of retaining accuracy and therefore discrimination. It is usual to allow for these errors by setting the relay to cover 80–85% of the line length in the first or instantaneous zone.

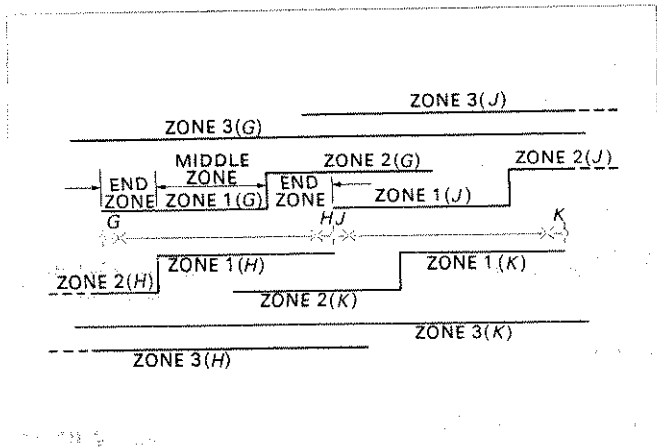


Figure 14.7 Typical three zone distance scheme.

Figure 14.7 illustrates a typical three-zone distance scheme covering two transmission lines. It will be seen that there is a zone near each end of the line in which faults are cleared by sequential tripping. These end zones usually represent 20–40% of the line length. The remaining 60–80% between the end zones is cleared simultaneously by the circuit breakers at both ends.

For this reason, a fault occurring in an end zone would be cleared in Zone 1 time, that is, instantaneously, by the protection at one end of the feeder but in 0.3–0.4 seconds (Zone 2 time) by the protection at the other end. High speed auto-reclosing applied to the circuit breakers at each end of the feeder could result either in no dead time or in a dead time insufficient to allow de-ionization of the fault arc. A transient fault could therefore be seen as a permanent one, resulting in the locking out of both circuit breakers.

Two methods are available for overcoming this difficulty: first, an extension of the reach of zone 1 to give instantaneous tripping over the whole line length, and secondly the use of a signalling channel to send a tripping signal to the far end of the line when a local zone 1 trip occurs.

### 14.10.1 Zone 1 extension

The Zone 1 extension scheme is used in conjunction with auto-reclosing to provide instantaneous tripping for end-zone transient faults. In this scheme the reach of Zone 1 is extended to 120% of the line length and is reset to 80% when a command from the auto-reclose relay is received. The auto-reclose relay contact used for this purpose should operate before a closing pulse is applied and remain operated until the end of reclaim time. The contact should also operate when the auto-reclose relay is out of service. The scheme is described in detail in Chapter 12.

### 14.10.2 Signalling Channels

A more satisfactory way to obtain instantaneous tripping over the whole length of a protected line is to use a signalling channel between the two ends. Signalling is carried out in various ways, using pilot wires or overhead conductors, radio link or microwave channel. The various methods used such as intertripping and blocking schemes are described fully in Chapter 12.

It suffices here to mention that when any of the schemes are used with high speed auto-reclosing, it is customary to provide an auto-reclose blocking relay to prevent the circuit breakers auto-reclosing for faults seen by the distance relay in Zones 2 and 3.

### 14.11

#### PHASE-TO-NEUTRAL VOLTAGE

Distance protection is ideally suited for use with single-phase auto-reclosing, since phase to earth measuring units are provided for each separate phase and can be used to initiate single-phase tripping and reclosing.

This is not the case with unit systems of protection, such as phase comparison and pilot wire protection, where a common output is provided for both phase and earth faults. With these protective schemes, additional phase selection relays must be used.

The types of phase selector relays available are now described.

#### 14.11.1 Voltage operation

The relay is supplied with phase to neutral voltage from one phase and phase to phase voltage across the other two phases. Operation of the relay occurs when the magnitude of the phase to neutral voltage falls below half the phase to phase voltage.

#### 14.11.2 Current operation

Measurement is made by comparing the negative and zero sequence currents in each phase and making use of the fact that in the faulty phase, for a phase to earth fault, the negative and zero sequence currents are in phase, whereas in the two healthy phases the current vectors are 120° out of phase.

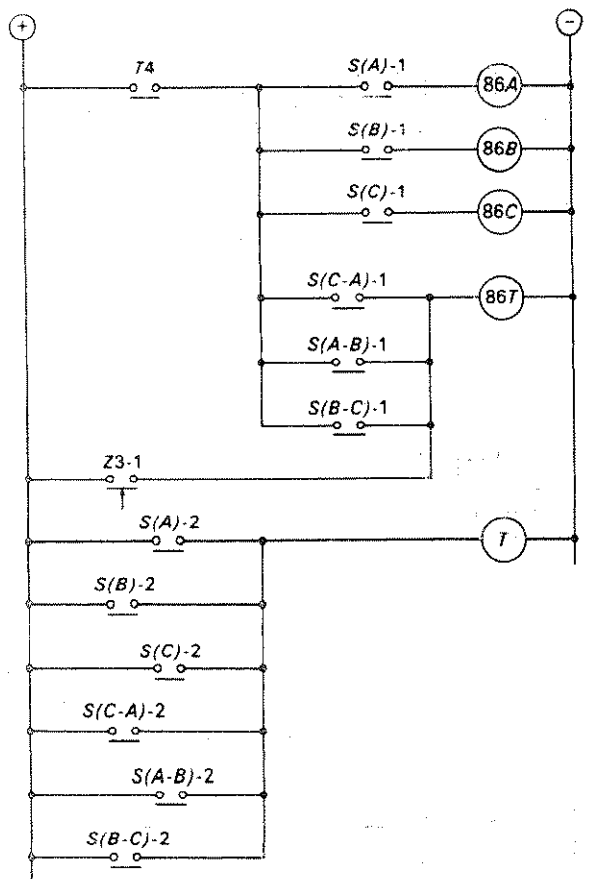
#### 14.11.3 Distance units

Mho starting units such as are employed in distance protection can be used as phase selection relays. A scheme using six units to measure phase to phase and phase to earth faults, in conjunction with a phase comparison scheme, is illustrated in Figure 14.8.

The detection of earth faults is carried out by means of the phase to earth starting units  $S(A)$ ,  $S(B)$ , and  $S(C)$  which select the appropriate tripping relay 86 according to which phase is faulty. For instance, an earth fault on the  $A$  phase, inside the protected line, would result in the phase comparison unit 74 and the starting unit  $S(A)$  closing their contacts to energize the single-phase tripping relay 86A. This in turn would trip the  $A$  pole of the circuit breaker and initiate single-phase auto-reclosing.

The detection of three-phase and phase to phase faults is carried out by means of the phase to phase starting units  $S(C-A)$ ,  $S(A-B)$  and  $S(B-C)$ . In the case of a phase to phase fault between the  $A$  and  $B$  phases, inside the protected line, both the phase comparison unit 74 and the starting unit  $S(A-B)$  will close their contacts and energize the

three-phase tripping relay 867. This in turn will trip the three poles of the circuit breaker and block auto-reclosing. The starting units can also be used to provide back-up protection for both phase and earth faults on the power system, within their normal reach, by means of a reed relay *T* which energizes a time delay relay *Z3*. On operation of the timer, its contact *Z3-1* closes and operates the three-phase tripping relay 867. This trips the three poles of the circuit breaker and blocks auto-reclosing.



|                               |                                                        |
|-------------------------------|--------------------------------------------------------|
| <i>T4</i>                     | Phase comparison contact                               |
| <i>S(A), S(B), S(C)</i>       | Phase selector relays ( mho starting units)            |
| <i>S(C-A), S(A-B), S(B-C)</i> | Phase to phase connected mho starting units            |
| <i>T</i>                      | Back-up control reed relay                             |
| <i>Z3</i>                     | Back-up timer                                          |
| 86A, 86B, 86C                 | Single-phase tripping and auto-reclose initiate relays |
| 867                           | Three-phase tripping and auto-reclose blocking relay   |

Figure 14.8 Phase selection relays for use with phase comparison scheme when used with single-phase auto-reclosing.

## 14.12

On highly interconnected transmission systems, where the loss of a single line is unlikely to cause two sections of the system to drift apart and lose synchronism, delayed auto-reclosing can be employed. The C.E.G.B. employ delayed auto-reclosing with dead times of the order of 5—60 seconds. No problems are presented by fault arc de-ioniza-

tion times and circuit breaker operating characteristics, and power swings on the system are permitted to settle down before reclosing. In addition, all tripping and reclose schemes can be three-phase only, simplifying control circuits in comparison with single-phase schemes.

In systems on which delayed auto-reclosing is permissible, the chances of a reclosure being successful are somewhat greater with delayed reclosing than would be the case with high speed reclosing. An analysis of their relative performance on the C.E.G.B. EHV system showed that high speed reclosing resulted in 68% of reclosure attempts being successful, while with delayed reclosing the figure rose to 77.5%.

### 14.12.1

#### Synchronism check relays

On a transmission line connecting two substations *G* and *H*, the circuit breakers at *G* and *H* respectively are tripped out in the event of a line fault. In a system on which delayed auto-reclosing is employed synchronism is unlikely to be lost, but the transfer of power through the remaining tie-lines on the system could result in the development of a voltage phase difference between points *G* and *H*, which would produce an unacceptable shock to the system if reclosure took place.

It is the usual practice, therefore, to incorporate a synchronism check relay into the reclosing system to determine whether auto-reclosing should take place. The relay commonly used for this duty gives a three-fold check:

- Phase angle difference
- Voltage difference
- Frequency difference

The phase angle setting is usually 20°, and the relay automatically holds up reclosure if the phase difference exceeds this value. Alternative phase angle settings of 35° or 45° are occasionally preferred. The scheme does not lock out, but waits for a reclosing opportunity with the phase angle within the set value.

A voltage check is incorporated to prevent reclosure if either voltage is less than a pre-set percentage of its rated value. The setting range is 80—90% of rated voltage.

The relay also incorporates a frequency difference check, by the simple expedient of using a timer in conjunction with the phase angle check. For example, if a 2 second timer is employed, the relay gives an output only if the phase difference does not exceed 20° over a period of 2 seconds. This limits the frequency difference to a maximum of 0.11% of 50Hz, corresponding to a phase swing from +20° to -20° over the measured 2 seconds. Although under the conditions considered a frequency difference is unlikely to arise, the time available during a delayed reclose operation allows this check to be carried out as an additional safeguard.

On the line *GH* referred to above, after tripping on a fault, it is normal procedure to reclose the breaker at one end first, a process known as 'dead line charging'.

Reclosing at the other end is then under the control of the synchronism check relay for what is known as 'live line reclosing'.

For example, if it were decided to charge the line initially from station *G*, the dead line charge timer in the auto-reclose relay at *G* would be set at, say, 5 seconds, while the corresponding timer in the auto-reclose relay at *H* would be set at, say, 15 seconds. The circuit breaker at *G* would then reclose after 5 seconds provided that voltage monitoring relays at *G* indicated that the busbars were alive and the line dead. With the line recharged, the circuit breaker at *H* would then reclose with a synchronism check, after a 2 second delay imposed by the check relay.

If for any reason the line fails to 'dead line charge' from end *G*, reclosure from end *H* would take place after 15 seconds.

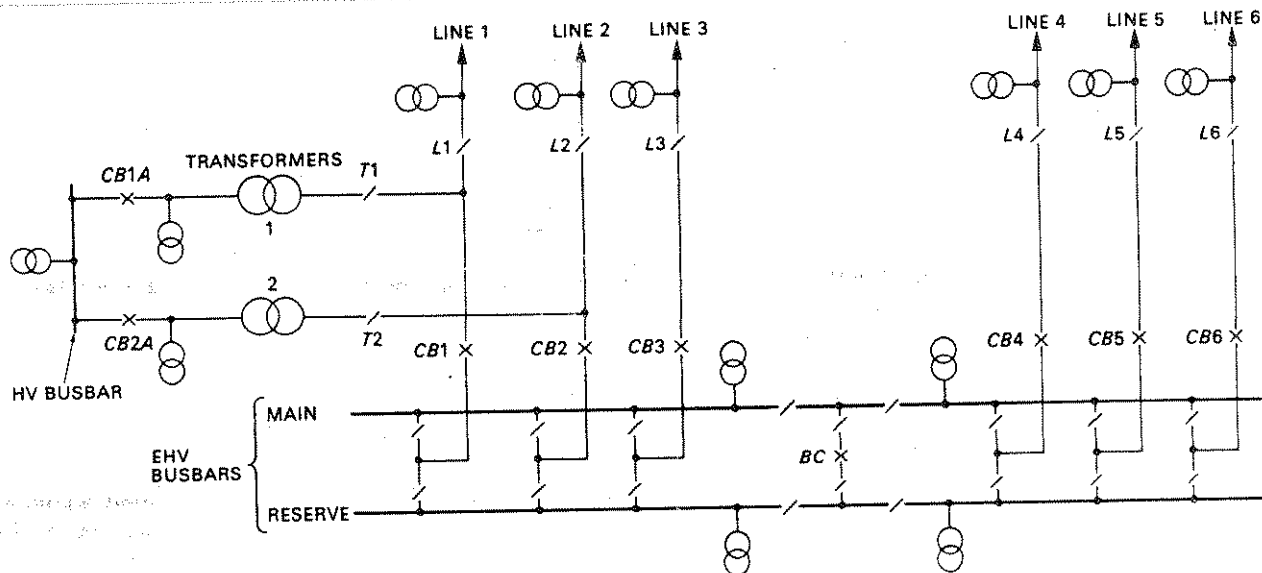


Figure 14.9 Double busbar extension.

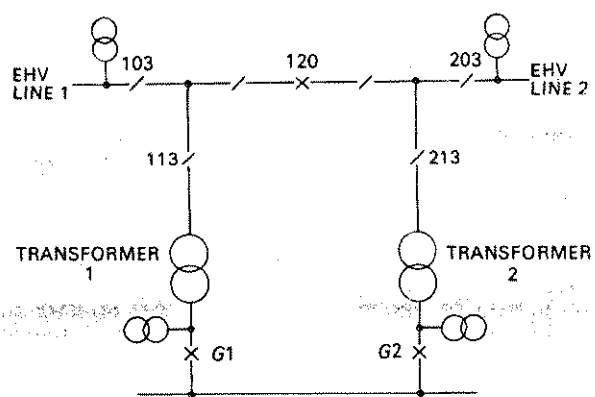


Figure 14.10 Single switch substation.

The circuit breaker at G would then be given the opportunity to reclose with a synchronism check.

Auto-reclose facilities in common use at a number of the standard substation configurations employed by the C.E.G.B. will now be described.

#### 14.12.2 Double busbar station

A typical double busbar station is illustrated in Figure 14.9. Each of the six EHV transmission lines brought into the station is under the control of a circuit breaker, CB1 to CB6, inclusive, and each line can be connected either to the main or to the reserve busbars by manually operated isolators.

Transformer circuits 1 and 2 are tee'd off lines 1 and 2 respectively. The transformer secondaries are connected to a separate HV busbar system via circuit breakers CB1A and CB2A.

Bus section isolators enable sections of busbar to be isolated in the event of fault and bus coupler breaker BC permits sections of main and reserve bars to be interconnected.

Each line circuit breaker is provided with an auto-reclose relay which, in the event of a line fault, recloses the breakers in the manner described in Section 14.12.1. Line and busbar voltage transformers feed the voltage monitoring relays, which determine whether conditions are right

for dead line charging or live line reclosing. The operation of either the busbar protection or a VT Buchholz relay is arranged to lock out the auto-reclosing sequence.

Auto-reclose facilities are extended to cover transformer circuits, where these are installed. For example, a fault on line 1 would cause the tripping of circuit breakers CB1, CB1A and the remote line circuit breaker. When line 1 is re-energized, either by auto-reclosure of CB1 or by the remote circuit breaker, whichever is set to reclose first, Transformer 1 is also energized. CB1A will not reclose until the appearance of transformer secondary voltage, as monitored by the secondary VT; it then recloses on to the HV busbars after a short time delay, with or without a synchronism check, as required.

In the event of a fault on Transformer 1, the local and remote line circuit breakers and breaker CB1A trip to isolate the fault; this is followed by an automatic opening of the transformer isolator T1, which is motor operated. The line circuit breakers then reclose in the normal manner and circuit breaker CB1A locks out.

In the event of a persistent fault on line 1, the line circuit breakers trip and lock out after one attempt at reclosure. A shortcoming of schemes used hitherto is that this results in the healthy Transformer 1 being isolated from the system; also, isolator L1 must be opened manually before circuit breakers CB1 and CB1A, can be closed to re-establish supply to the HV bars via the transformer.

#### 14.12.3 Single switch substation

The arrangement shown in Figure 14.10 consists basically of two transformer feeders interconnected by a single circuit breaker 120. Each transformer therefore has an alternative source of supply in the event of loss of one or other of the feeders.

For example, a transient fault on line 1 causes tripping of circuit breakers 120 and G1 followed by reclosure of 120. If the reclosure is successful, Transformer 1 is re-energized and circuit breaker G1 recloses after a short time delay.

If the line fault is persistent, 120 trips again and the motorized line isolator 103 is automatically opened. Circuit breaker 120 recloses again, followed by G1, so that both Transformers 1 and 2 are then supplied from line 2.

A transformer fault causes the automatic opening of the appropriate transformer isolator, lock-out of the transformer secondary circuit breaker and reclosure of circuit breaker 120.



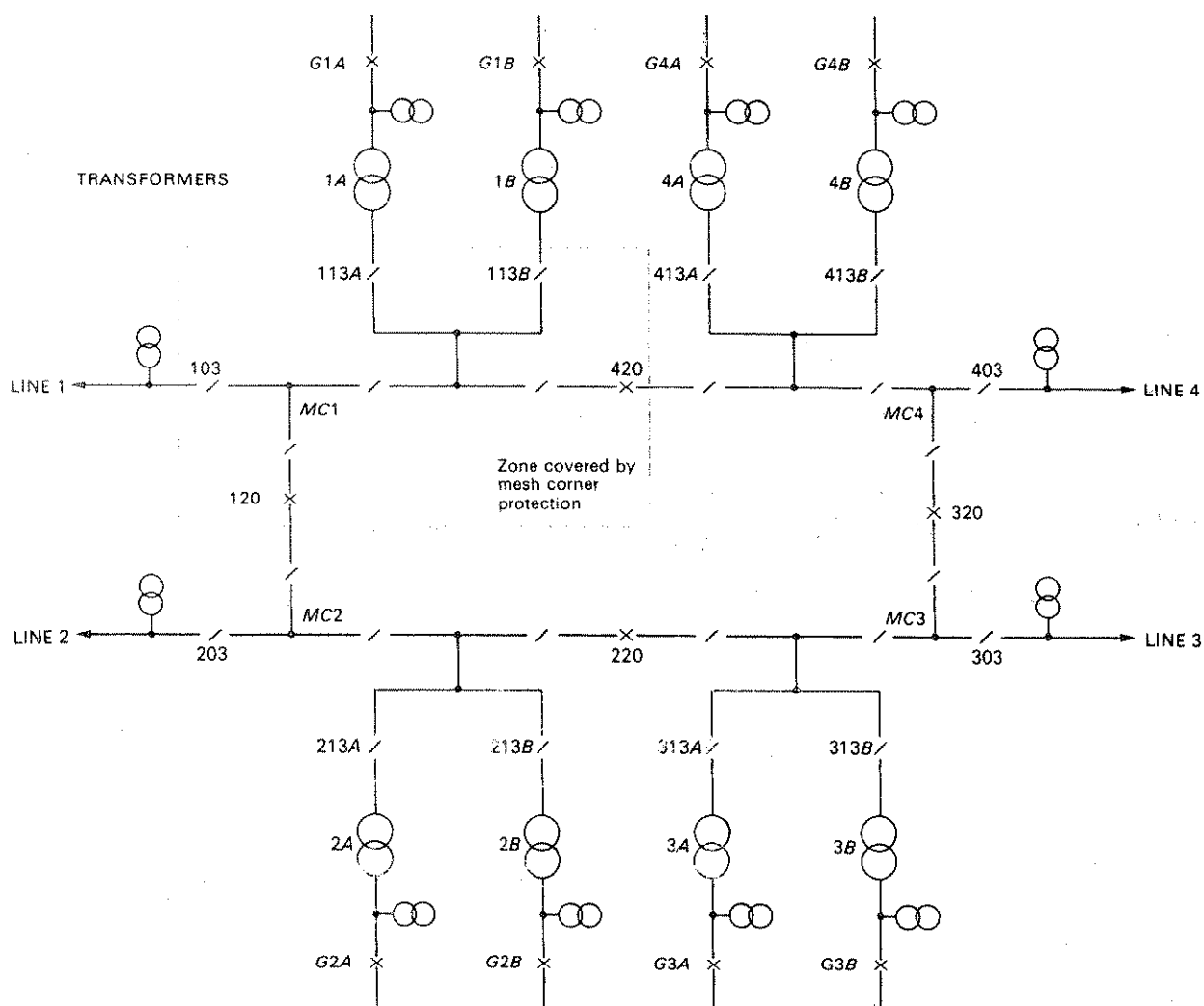


Figure 14.11 Four-switch mesh substation.

Facilities for dead line charging or reclosure with synchronism check are provided for each circuit breaker.

#### 14.12.4

##### Four-switch mesh substation

The mesh substation illustrated in Figure 14.11 is extensively used by the C.E.G.B. either in full or in part. One or two transformers and a feeder are banked at each corner of the mesh. This station configuration, using four EHV circuit breakers to complete the mesh interconnection, is not operationally ideal but is justified on grounds of economy. It has been estimated that if banking were not permitted, a fifteen-switch double busbar station would be required in place of the four-switch mesh.

Considerable problems were encountered in the application of auto-reclosing to the mesh station. For example, circuit breakers 120 and 420 in Figure 14.11 are tripped out for a variety of different types of fault associated with mesh corner 1 (MC1), and each requires different treatment as far as auto-reclosing is concerned. Further variations occur if the faults are persistent.

Following normal C.E.G.B. practice, circuit breakers must be reclosed in sequence, so sequencing circuits are necessary for the four mesh breakers. Closing priority may be in any order, but is normally 120, 220, 320, 420.

A summary of facilities is now given, based on mesh corner 1; facilities at other corners are similar.

##### a. Transient fault on line 1

Tripping of circuit breakers 120, 420, G1A, G1B is followed by reclosure of 120 to give dead line charging of line 1. Breaker 420 recloses in sequence, with a synchronism check. Breakers G1A, G1B reclose with a synchronism check if necessary.

##### b. Persistent fault on line 1

Circuit breaker 120 trips again after the first reclosure and isolator 103 is automatically opened to isolate the faulted line. Breakers 120, 420, G1A, G1B then reclose in sequence as above.

##### c. Transformer fault (local transformer 1A)

Tripping of circuit breakers 120, 420, G1A, G1B is followed by automatic opening of isolator 113A to isolate the faulted transformer. Breakers 120, 420 and G1B then reclose in sequence, and breaker G1A is locked out.

##### d. Transformer fault (remote transformer)

For a remote transformer fault, an intertrip signal is received at the local station, which in addition to tripping breakers 120, 420, G1A and G1B inhibits auto-reclosing until the faulted transformer has been isolated at the remote station. If the intertrip persists for 60 seconds it is assumed that the fault cannot be isolated at the remote station, whereupon isolator 103 is automatically opened and circuit breakers 120, 420, G1A and G1B are reclosed in sequence.

##### e. Transient mesh corner fault

Any fault covered by the mesh corner protection zone,



shown in Figure 14.11, results in tripping of circuit breakers 120, 420, G1A and G1B, which are then reclosed in sequence. The scheme provides the option of locking out the circuit breakers, in situations for which it has been decided that reclosure on to mesh corner faults is to be avoided.

#### f. *Persistent mesh corner fault*

Following an unsuccessful attempt at reclosure by circuit breaker 120, which will again trip, all circuit breakers are locked out and the line isolator 103 is automatically opened to isolate the fault from the remote station.

### 14.13

#### FEATURES OF LINE SCHEMES

The extensive use of auto-reclosing has resulted in the existence of a wide variety of different control schemes. Some of the more important variations in the features provided are described below.

#### 14.13.1

##### Initiation

There are two main methods of initiating auto-reclosing:

- i. Circuit breaker auxiliary switch.
- ii. Protective relay contact.

In the first method, an auxiliary switch makes when the circuit breaker opens, energizing the auto-reclose scheme via an auto-manual selector switch. Technically this is quite satisfactory, but if the breaker were tripped manually with the selector switch left inadvertently in the auto position, an unwanted reclosure would follow. This could be a potential danger to personnel if the breaker were tripped for maintenance purposes with the auto-reclose relay set to a long dead time, since work could have started on the breaker by the time it reclosed.

The second method, initiation by protective relay contact, is generally preferred, since accidental reclosing cannot take place.

Many auto-reclose schemes incorporate a starting relay element, which is energized by the initiating contact and retained by a self-sealing contact. Any interlocks needed to prevent initiation unless certain conditions are satisfied are connected in series with the starting relay energizing coil. Some examples of these, which vary from scheme to scheme, are as follows:

- a. In schemes using protective relay initiation, a circuit breaker normally open auxiliary switch, to check that the breaker was closed at the instant of the fault.
- b. Line voltage interlock, to check that the line was alive before auto-reclose initiation.
- c. Where motor-wound spring operated breakers are employed, an auxiliary switch on the winding mechanism to prevent initiation unless the spring is fully charged.
- d. Where air blast circuit breakers are employed, an air pressure interlock to prevent initiation when circuit breaker air pressure is low.

Contacts from other devices, such as busbar protection and VT Buchholz relays, are connected into the starting circuit outside its self-sealing contact, so that operation at any time during the auto-reclose sequence causes immediate cancellation.

#### 14.13.2

##### Facilities related to type of protection

On HV distribution systems, where advantage is taken of auto-reclosing to use instantaneous protection for the first trip, followed by I.D.M.T. for subsequent trips in any one fault incident, the auto-reclose relay must provide a means of isolating the instantaneous relay after the first trip. This is normally done with a normally closed contact on the

auto-reclose starting element wired into the connection between the instantaneous relay contact and the circuit breaker trip coil.

Self-clearing faults of extremely short duration are experienced on some HV systems. These faults may operate the protection, giving the circuit a tripping impulse, but their duration is insufficient to initiate the auto-reclose relay, resulting in a trip but no reclosure. When such faults are likely, steps must be taken to speed up the auto-reclose starting element so that it responds to a pulse of 5 or 6ms. One method of doing this is to use the protection impulse to charge a capacitor, which can then discharge through the starting relay coil at a rate slow enough to enable it to pick up and seal in.

With certain supply authorities it is the rule to fit tripping relays with every circuit breaker. If auto-reclosing is required, these tripping relays must be the electrically reset type, and a contact must be provided on the auto-reclose relay to energize the reset coil before reclosing can take place.

#### 14.13.3

##### Dead timer

This is usually an electromechanical or static timer with a timing range to cover the specified high speed or low speed reclosing duty. Occasionally, if high speed reclosing is required, a timer can be dispensed with, the dead time being governed by the circuit breaker characteristics and auxiliary switch settings.

Any interlocks which are needed to hold up reclosing until conditions are suitable can be connected into the dead timer circuit. For example, in the busbar station of Figure 14.9, circuit breaker CB1A is not reclosed until Transformer 1 is re-energized as monitored by its secondary VT. A voltage monitoring relay contact in series with the dead timer makes certain of this function. Similarly, if CB1A were an air blast breaker, its low air pressure interlock contact could be connected in series with the dead timer, so that if air pressure were initially low, reclosing would not occur before the restoration of pressure to its normal value.

#### 14.13.4

##### Reclosing impulse

The duration of the reclosing impulse must be related to the requirements of the circuit breaker closing mechanism.

On auto-reclose schemes for spring closed breakers, it is sufficient to operate a contact, at the end of the dead time, to energize the latch release solenoid on the spring closing mechanism. A circuit breaker auxiliary switch can be used to cancel the closing pulse and reset the auto-reclose relay.

With solenoid operated breakers, it is usual to provide a closing pulse of the order of 1–2 seconds, so as to hold the solenoid energized for a short time after the main contacts have closed, ensuring that the mechanism settles in the fully latched-in position. In electromechanical auto-reclose schemes, it is convenient to use a 'passing contact' on the dead timer for this purpose. Schemes employing static timers require a separate closing pulse timer.

As far as the pneumatic closing mechanisms fitted to oil and air blast circuit breakers are concerned, a circuit breaker auxiliary switch is adequate for terminating the closing pulse applied by the auto-reclose relay, and a number of schemes operate on this basis. However, other schemes which provide a timed reclosing impulse lasting 1–2 seconds are equally satisfactory.

#### 14.13.5

##### Anti-pumping devices

The function of an anti-pumping device is to prevent the circuit breaker closing and opening several times in quick succession, which might be caused by the application of a

closing pulse while the circuit breaker is being tripped via the protective relays. This may occur if the circuit breaker is closed on to a fault and the closing pulse is longer than the sum of protective relay and circuit breaker operating times.

Circuit breakers with trip free mechanisms do not require this feature, but solenoid operated breakers must have no auxiliary switches connected in series with the closing coil or contactor, as otherwise the anti-pumping arrangement will be nullified.

On solenoid operated mechanisms the anti-pumping feature is obtained by keeping the solenoid energized for the duration of the closing pulse; this holds the plunger up and prevents resetting until the pulse is removed.

Although most manufacturers of solenoid operated circuit breakers recommend that the closing pulse be maintained for a short time after the main contacts make, which prevents the use of auxiliary switches to cut off the closing pulse, there are some types on the market that permit the use of auxiliary switches. In such cases, it will be necessary to provide an anti-pumping device.

Pneumatic closing systems for oil circuit breakers also vary with the manufacturer. Some designs have a trip free mechanism similar to that of a solenoid breaker, and of themselves prevent pumping, provided that the closing air supply is maintained for the duration of the closing pulse.

Other types of pneumatically operated oil circuit breakers can be made to operate as if they had a trip free mechanism by means of a 'dump valve' in the closing cylinder, which opens the closing side of the piston to exhaust in the event of a closing pulse preceding a tripping pulse. This does not, however, provide an anti-pumping feature, and care must be exercised to ensure that the auto-reclose scheme includes an anti-pumping circuit or hand reset lockout relay. With these mechanisms, auxiliary switches can be used to cut off the closing coil.

Air blast breakers have fixed trip mechanisms, so that it is not possible to make the tripping pulse take precedence over the closing pulse. With these breakers it is necessary to provide anti-hunting circuits. Auxiliary contacts may be used in the closing circuit if desired.

A further development with air blast breakers is the inclusion of a pneumatic anti-pumping device, obviating the need for a separate electrical circuit.

Figure 14.12 shows a typical circuit breaker anti-pumping circuit. A manual control switch 'CS' is shown for giving the closing pulse; in an auto-reclose relay initiation would be by means of the appropriate timer contact.

With the circuit breaker open, operation of the switch to the closing position would pick up relay 94A, which seals itself in through contact 94A-1. At the same time, contact 94A-2 energizes 94B, which opens the normally closed contact 94B-1 and seals itself in via 94B-2.

Since both relays 94A and 94B are energized, contacts 94A-3 and 94B-3 are closed. These energize the closing coil 52C and the circuit breaker closes.

As soon as the circuit breaker closes, auxiliary contacts 52b open and de-energize relay 94A and the closing coil 52C. If the breaker stays in, on release of the control switch, relay 94B will be de-energized and the scheme will return to its original state.

However, if the circuit breaker trips out because the protective relay has operated with control switch CS still in the closed position, the breaker will not be able to reclose, as relay 94A is de-energized and contact 94A-3 in the closing coil circuit is open.

The circuit breaker will stay open as long as the control switch CS is kept in the close position and can be reclosed only if the control switch is first released and then returned to the close position by the operator.

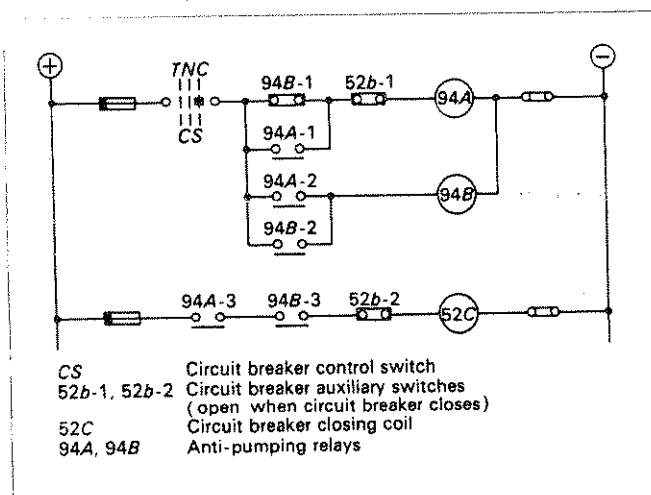


Figure 14.12 Anti-pumping relay control circuit.

#### 14.13.6 Reclaim timer

Various methods are used to provide the reclaim time.

In one of the simplest schemes, a capacitor is maintained in a charged condition when the relay is in service. On the occurrence of a fault, the capacitor is discharged through the coil of a relay element, which picks up and seals in, and initiates auto-reclosure. After reclosure, the relay will not respond to further faults until the capacitor has been recharged via a resistor. The reclaim time is therefore determined by the time constant of the RC circuit.

An electromechanical or static timer is most commonly used to give the reclaim time. If electromechanical timers are used, it is convenient to employ two independently adjustable timed contacts to obtain both the dead time and the reclaim time on one timer.

When motor-wound spring operated circuit breakers are used, the winding time of the spring can be used as the reclaim time, provided that the winding time is long enough to satisfy operational requirements, as laid down in Section 14.5.2. A contact is connected into the auto-reclose initiation circuit to prevent initiation until the spring is wound.

#### 14.13.7 Lock-out

If reclosure is unsuccessful the auto-reclose relay locks out the circuit breaker. Some schemes provide a lock-out relay with a flag, with the optional provision of a contact for remote alarm. The circuit breaker can only be closed by hand; this action can be arranged to reset the auto-reclose relay automatically. Alternatively, hand reset relays can be provided, which require individual attention.

Some schemes lock themselves out after one reclosure attempt regardless of whether the fault is transient or permanent. This would be the case with hand-wound spring-operated breakers, which require hand winding after each operating cycle.

Circuit breaker manufacturers state the maximum number of operations allowed before maintenance is required. A number of schemes provide a counting relay to count reclosures and give a warning when the total is one short of the manufacturer's recommendation. Lock-out takes place after the next reclosure and an additional alarm is given.

#### 14.13.8 Manual closing

If a circuit breaker is closed on to a fault manually, it is undesirable to permit auto-reclosing. It is therefore common practice to interlock the manual closing switch with

the auto-reclose selector switch so that manual closing can take place only with auto-reclosing switched out of service.

Another method is to arrange for manual closing via the closing impulse circuit in the auto-reclose relay, so that the reclaim timer also operates and locks out the breaker if it closes on to a fault.

#### 14.13.9

##### Single-phase auto-reclose schemes

On the occurrence of a phase to earth fault, single-phase auto-reclose schemes trip and reclose only the faulty phase pole of the circuit breaker. The auto-reclose relay is therefore fitted with three separate starting elements, one for each phase. Operation of any starting element energizes the dead timer, which in turn initiates a closing pulse for the appropriate pole of the circuit breaker.

A successful reclosure results in the relay resetting at the end of the reclaim time, ready to respond to a further fault incident, but if the fault is persistent, the normal arrangement is to trip and lock out all three poles of the circuit breaker.

Three-phase trip and lock out also occurs for a phase to phase fault or if either of the remaining phases should develop a fault during the dead time.

Other schemes are available in which a selector switch gives the choice of single or three-phase reclosing. Single-phase operation is as described above, while three-phase operation gives three phase tripping and reclosing for any phase or earth fault, with three-phase lock-out of the circuit breaker if the fault is persistent.

Another variant is a scheme which gives combined single and three-phase auto-reclosing; single phase to earth faults initiate single-phase tripping and reclosure, and phase to phase faults initiate three-phase tripping and reclosure.

#### 14.13.10

##### Multi-shot schemes

One scheme providing up to four shots is based on a version of the standard electromechanical timer on which the passing contact is operated up to four times by four adjustable operating arms, to give up to four separate reclosing impulses.

Other schemes providing up to three or four shots use static timing circuits to provide different, independently adjustable, dead times for each shot.

Instantaneous protection can be used for the first trip, since each scheme provides a contact to cut out instantaneous protection after the first trip and allows I.D.M.T. protection to take over for subsequent trips.

Each scheme resets if reclosure is successful within the chosen number of shots, ready to respond to further fault incidents. In the scheme using the multi-shot electromechanical timer, an additional timer contact, set to operate at a fixed time interval after the passing contact has completed its chosen number of impulses, provides the reclaim time after the final shot. In the scheme using static timers, another independently adjustable static timer circuit provides the reclaim time.

#### 14.14

##### Static Timing Equipment

The extent to which static circuit techniques can be usefully and economically applied in place of electromechanical equipment in auto-reclose schemes depends on the complexity of each particular scheme. Most auto-reclose schemes use a hinged armature relay for circuit breaker closing, because of the contact rating required. In the simplest three phase, single shot schemes using a few electromechanical relays for sequence control, it is unlikely

that the substitution of a static logic circuit would give a significant saving in space or cost; but the use of static timing circuits instead of the electromechanical timer, can improve the range of time settings available.

More complex schemes, such as those for multi-shot or single and/or three phase reclosing of a feeder circuit breaker, or for auto-reclose control of a complete substation such as the four switch mesh shown in Figure 14.11, can benefit substantially from the application of static circuit techniques. Auto-reclose schemes for such applications have been produced in the past, using integrated circuits incorporating logic gates, but this has now been largely replaced by microprocessor schemes which allow one set of hardware to be programmed for a variety of different applications.

The use of PERM 200 equipment to control delayed auto-reclosing of all circuit breakers at a substation is described in Section 22.13. Simpler microprocessor based schemes are available for auto-reclose control of individual feeders.

The MVTR51 relay illustrated in Figure 14.13 provides three phase single or multi-shot auto-reclosing for a distribution feeder. Scheme logic is contained in the microprocessor software, and is presented as a 'ladder diagram' which represents the scheme in contact logic form, equivalent to a combination of discrete component relays, contacts, timers and counters.

The relay operating sequence can be followed in a way similar to the use of a schematic diagram for electro-mechanical schemes. Variations in the operating cycle,

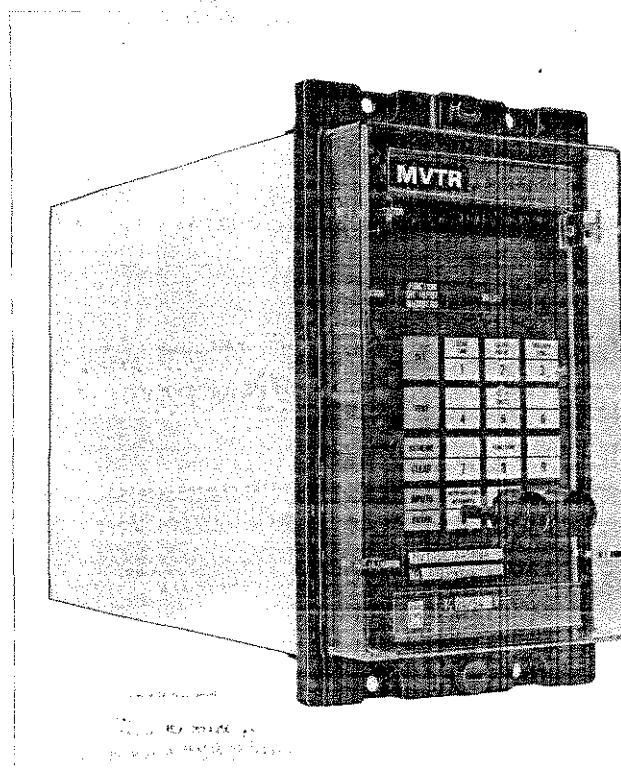


Figure 14.13 Multi-shot auto-reclose relay.

such as the number of shots, or auto-reclose attempts (1, 2, 3 or 4), and all timer settings (first, second, third and fourth shot dead times, close pulse duration and reclaim time) are very simply selected using the keypad on the relay frontplate. Timer settings and scheme variations are clearly indicated on the liquid crystal display. A block diagram of the MVTR51 relay is shown in Figure 14.14.

An enhanced version of this relay has additional input and output facilities plus a fault trips counter which locks out the auto-reclose scheme when the circuit breaker has performed a preset number of fault trips, that is, the 'Maintenance Lockout'. An 'Inspection Alarm', or pre-lockout

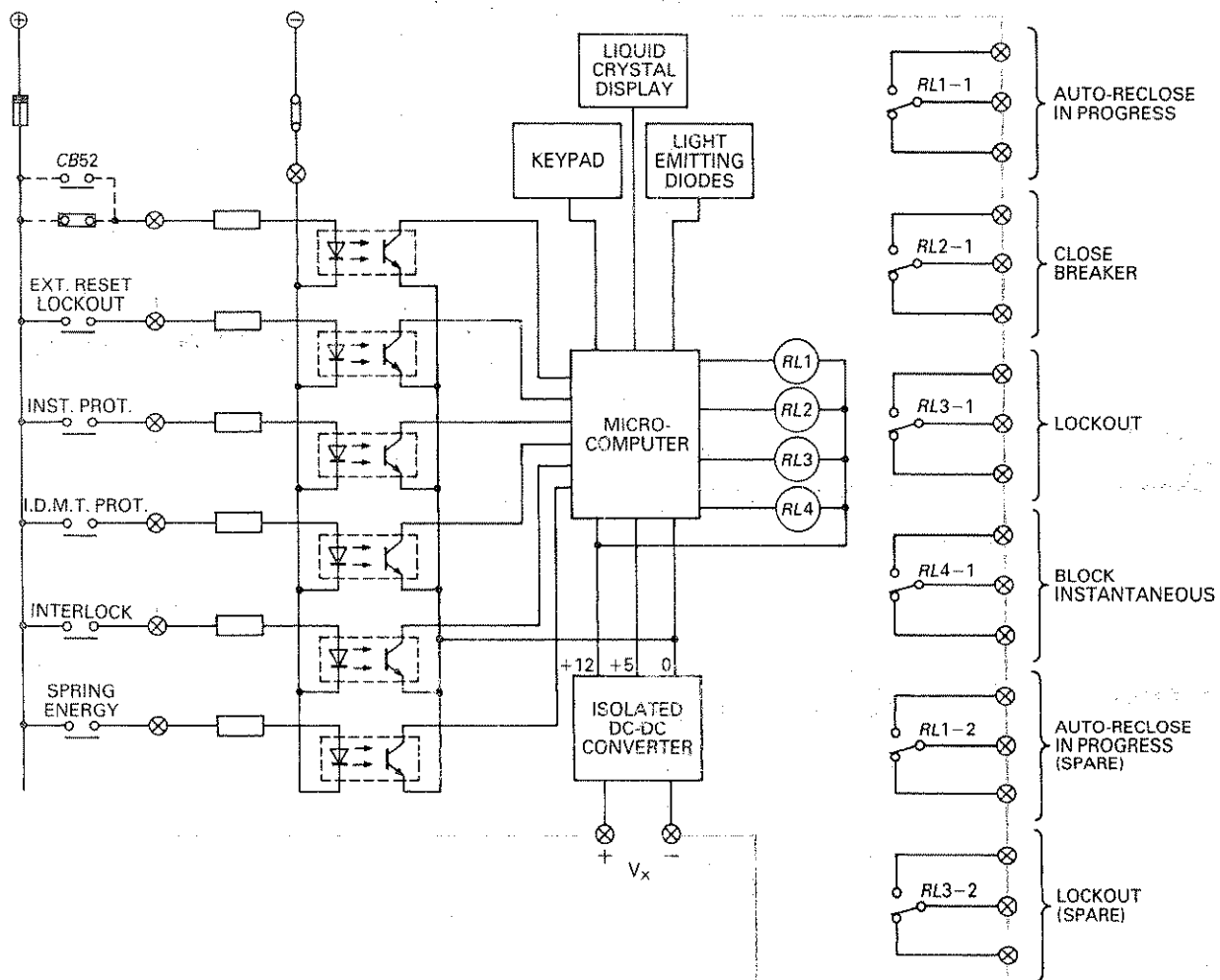


Figure 14.14 Block diagram of multi-shot auto-reclose relay type MVTR51.

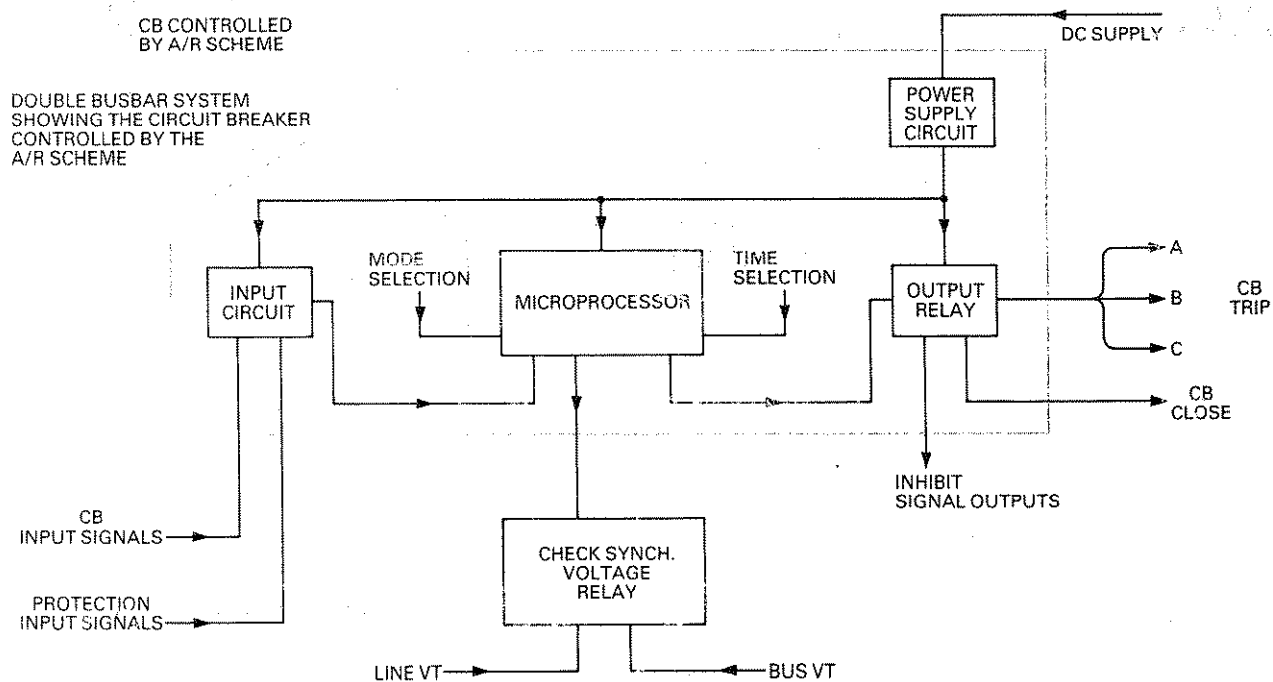


Figure 14.15 Modular microprocessor based auto-reclose relay for single breaker.

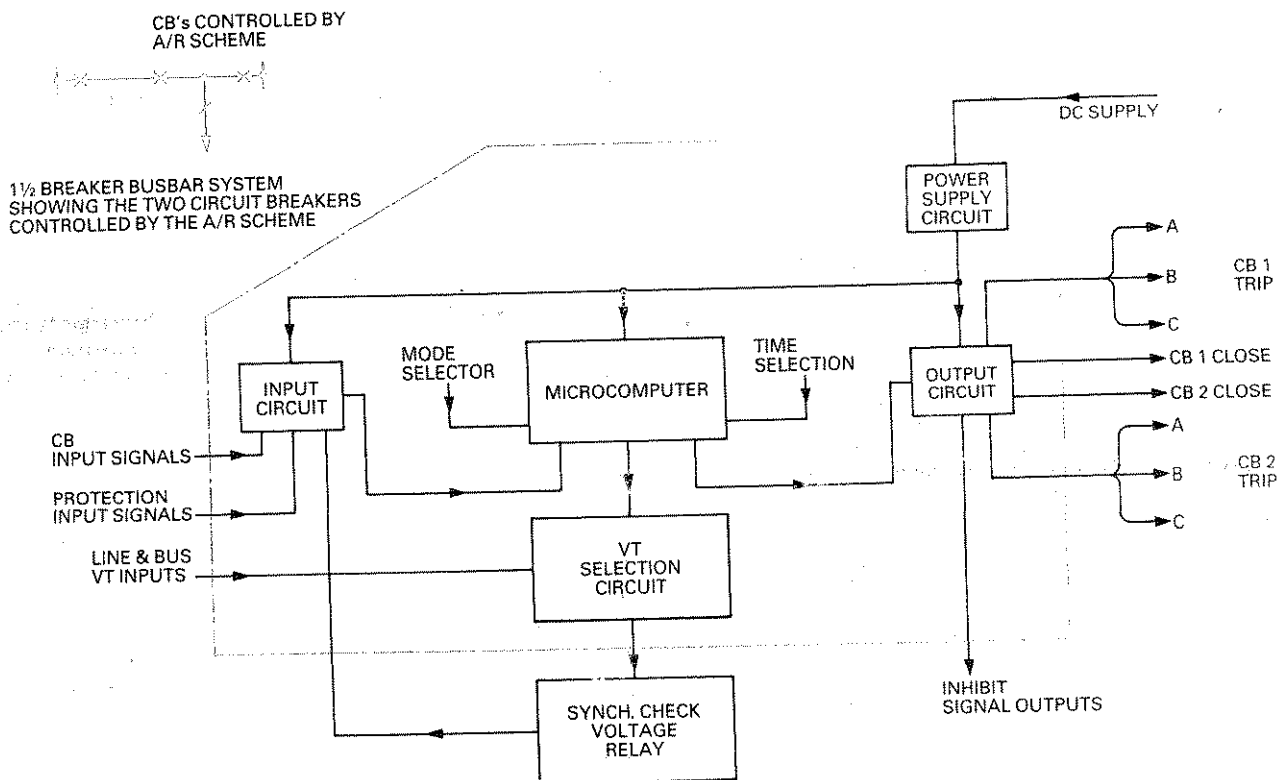


Figure 14.16 Modular microprocessor based auto-reclose relay for double breaker.

warning, is given when the fault trips count is approaching the lockout setting.

Block diagrams of modular microprocessor based schemes providing single or two shot, single and/or three phase auto-reclosing for a transmission line end controlled by either one or two circuit breakers are shown in Figures 14.15 and 14.16 respectively. Facilities are provided in these schemes for synchronism check or dead line check before auto-reclosing can take place.

## 14.15

### 14.15.1

Auto-close schemes are employed to close automatically circuit breakers which are normally open when the supply network is healthy. The circuits involved are very similar to those used for auto-reclosing.

Two typical applications are now described.

### 14.15.1

#### Standby transformers

Figure 14.17 shows a busbar station fed by three transformers, T1, T2 and T3. The loss of one transformer could cause serious overloading of the remaining two, yet to overcome this by the connection of a further transformer might raise the fault level to an unacceptable value. The solution is to have a standby transformer T4 permanently energized from the primary side and arranged to be switched into service if one of the others trips on fault.

The operation of transformer protection on any of the transformers T1, T2 and T3 together with the tripping of an associated circuit breaker G1, G2 or G3 is monitored by the starting circuits for breaker G4. In the event of a fault, the auto-close circuit is initiated and circuit breaker G4 closes, after a short time delay, to switch in the standby trans-

former. Some schemes employ an auto-tripping relay, so that when the faulty transformer is returned to service, the standby is automatically disconnected.

### 14.15.2

#### Bus coupler or bus section breaker

If in the power supply arrangement shown in Figure 14.17 all four power transformers are normally in service, and the busbars may be interconnected by a normally-open bus section breaker instead of the isolator, the bus section breaker should be auto-closed in the event of the loss of one transformer, to spread the load over the three others.

Starting and auto-trip circuits are employed as in the stand-by scheme. The auto-close relay used in practice is a variant of one of the standard auto-reclose relays used at busbar stations.

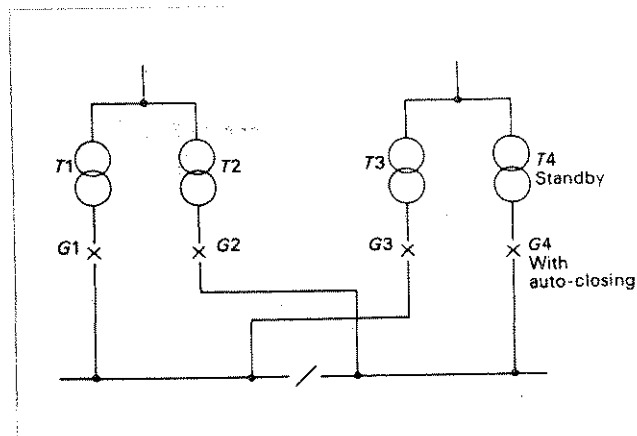
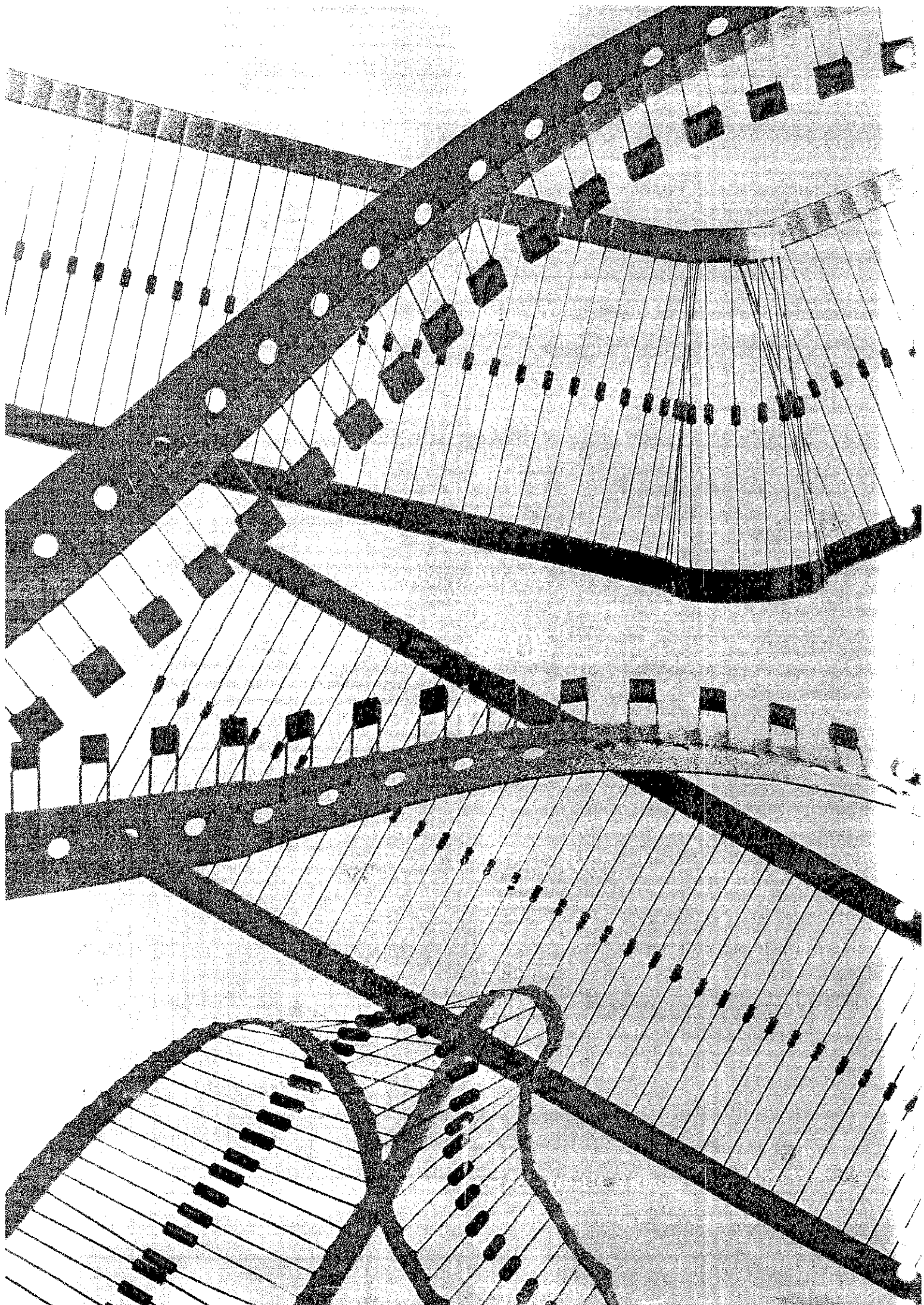


Figure 14.17 Standby transformer with auto-closing.





# Busbar protection

- 15.1 Introduction.
- 15.2 Busbar faults.
- 15.3 Protection requirements.
- 15.4 Types of protection system.
- 15.5 Single-earth protection (Howard protection).
- 15.6 Differential protection.
- 15.7 High impedance differential protection (MBCZ).
- 15.8 High impedance differential busbar protection schemes.
- 15.9 Calculations for high impedance differential schemes.
- 15.10 Impedance differential protection (MBCZ).
- 15.11 Impedance biased differential protection type MBCZ.
- 15.12 Union of current transformers.
- 15.13 Circuits.

## 15.1

### INTRODUCTION

The protection scheme for a power system should cover the whole system against all probable types of fault. Unrestricted forms of line protection, such as overcurrent and distance systems, meet this requirement, although faults in the busbar zone are cleared only after some time delay. But if unit protection is applied to feeders and plant, the busbars are not inherently protected.

Busbars have often been left without specific protection, for one or more of the following reasons:

- a. The busbars and switchgear have a high degree of reliability, to the point of being regarded as intrinsically safe.
- b. It was feared that accidental operation of busbar protection might cause widespread dislocation of the power system, which, if not quickly cleared, would cause more loss than would the very infrequent actual bus faults.
- c. It was hoped that system protection or back-up protection would provide sufficient bus protection if needed.

It is true that the risk of a fault occurring on modern metal-clad gear is very small, but it cannot be entirely ignored. However, the damage resulting from one uncleared fault, because of the concentration of fault MVA, may be very extensive indeed, up to the complete loss of the station by fire. Serious damage to or destruction of the installation would probably result in widespread and prolonged supply interruption.

On the other hand, if the busbar is subdivided into sections, each of which is separately protected, a fault in one such section does not involve the tripping of the complete station. Important loads can then be fed from two or more sections, and will not suffer any interruption of supply if one section is tripped.

Modern busbar protection is stable and free from unnecessary operation during through faults. Precautions are taken to avoid accidental operation being caused by outside interference.

Finally, system protection will frequently not provide the cover required. Such protection may be good enough for small distribution substations, but not for important stations. Even if distance protection is applied to all feeders, the busbar will lie in the second zone of all the distance protections, so a bus fault will be cleared relatively slowly, and the resultant duration of the voltage dip imposed on the rest of the system may not be tolerable.

| Cause of fault                              | Type and number of faults |                     |                       |             |         | Totals | Percentage of each cause of fault |
|---------------------------------------------|---------------------------|---------------------|-----------------------|-------------|---------|--------|-----------------------------------|
|                                             | Phase to earth            | Two phases to earth | Three phases to earth | Three-phase | Unknown |        |                                   |
| Flashover                                   | 20                        | 6                   | 1                     | —           | —       | 27     | 21.0                              |
| Breaker failure                             | 16                        | 2                   | 2                     | —           | —       | 20     | 15.5                              |
| Switchgear insulation failure               | 19                        | 2                   | —                     | —           | 1       | 22     | 17.0                              |
| Insulation failure other than switchgear    | 4                         | 1                   | 1                     | 3           | —       | 9      | 7.0                               |
| Current transformer failure                 | 3                         | —                   | —                     | —           | —       | 3      | 2.3                               |
| Isolators opened on load or closed to earth | 8                         | 1                   | 5                     | 1           | —       | 15     | 11.6                              |
| Safety earths left on                       | 6                         | 1                   | 8                     | —           | —       | 15     | 11.6                              |
| Accidental contact                          | 5                         | —                   | 2                     | —           | —       | 7      | 5.4                               |
| Falling debris                              | 4                         | 1                   | —                     | 1           | —       | 6      | 4.7                               |
| Miscellaneous and unknown                   | 2                         | 1                   | —                     | 1           | 1       | 5      | 3.9                               |
| Total of each type of fault                 | 87                        | 15                  | 19                    | 6           | 2       | 129    | —                                 |
| Percentage of each type of fault            | 67.4                      | 11.6                | 14.7                  | 4.7         | 1.6     | —      | 100                               |

Table 15.1 Fault statistics.

With outdoor switchgear the case is less clear since, although the likelihood of a fault is higher, the risk of widespread damage resulting is much less. In general then, busbar protection is required when the system protection does not cover the busbars, or when, in order to maintain power system stability, high speed fault clearance is necessary. Unit busbar protection provides this, with the further advantage that if the busbars are sectionalized, one section only need be isolated to clear a fault. The case for unit busbar protection is in fact strongest when there is sectionalization.

## 15.2

The majority of bus faults involve one phase and earth, but faults arise from many causes and a significant number are interphase clear of earth. In fact, a large proportion of busbar faults result from human error rather than the failure of switchgear components.

With fully phase-segregated metalclad gear, only earth faults are possible, and a protective scheme need have earth fault sensitivity only. In other cases, an ability to respond to phase faults clear of earth is an advantage, although the phase fault sensitivity need not be very high. Table 15.1 gives an analysis of 129 bus faults which occurred on a number of power systems.

## 15.3

Although not basically different from other circuit protection, the key position of the busbar intensifies the emphasis put on the essential requirements of speed and stability. The special features of busbar protection are discussed below.

### 15.3.1 Speed

Busbar protection is primarily concerned with:

- Limitation of consequential damage.
- Removal of bus faults in less time than could be

achieved by back-up line protection, with the object of maintaining system stability.

Some early bus protection used a low impedance differential system having a relatively long operating time, of up to 0.5 seconds.

The basis of most modern schemes is a differential system using either low impedance biased or high impedance unbiased relays capable of operating in a time of the order of one cycle at a very moderate multiple of fault setting. To this must be added the operating time of the tripping relays, but an overall tripping time of less than two cycles can be achieved. With high speed circuit breakers, complete fault clearance may be obtained in approximately 0.1 seconds.

When a frame-earth system is used, the operating speed is comparable.

### 15.3.2 Stability

The stability of bus protection is of paramount importance. Bearing in mind the low rate of fault incidence, amounting to no more than an average of one fault per busbar in twenty years, it is clear that unless the stability of the protection is absolute, the degree of disturbance to which the power system is likely to be subjected may be increased by the installation of bus protection. Fear of this led to hesitation in applying bus protection and also resulted in the designing of some very complex systems. Increased understanding of the response of differential systems to transient currents enables such systems to be applied with confidence in their fundamental stability. The theory and practical application of differential protection is given later, in Sections 15.7.1 and 15.10.2.

Notwithstanding the complete stability of a correctly applied protective system, dangers exist in practice for a number of reasons. These are:

- Interruption of the secondary circuit of a current transformer will produce an unbalance, which might cause tripping on load, depending on the relative values of circuit load and effective setting. It would certainly do so during a through fault, producing substantial fault current in the circuit in question.



b. A mechanical shock of sufficient severity may cause operation.

c. Accidental interference with the relay, arising from a mistake during maintenance testing, may lead to operation.

In order to maintain the high order of integrity needed for bus protection, it is an almost invariable practice to make tripping depend on two independent measurements of fault quantities. Moreover, if the tripping of all the breakers within a zone is derived from common measuring relays, two separate elements must be operated at each stage to complete a tripping operation. In many cases, the relays are separated by at least six feet so that no reasonable accidental mechanical interference to both relays simultaneously is possible.

The two measurements may be made by two similar differential systems, or one differential system may be checked by a frame-earth system, by earth fault relays energized by current transformers in the transformer neutral-earth conductors or by overcurrent relays. Alternatively, a frame-earth system may be checked by earth fault relays.

If two systems of the differential or other similar type are used, they should be energized by separate current transformers in the case of high impedance unbiased differential schemes.

The duplicate ring CT cores may be mounted on a common primary conductor but independence must be maintained throughout the secondary circuit.

In the case of low impedance, biased differential schemes that cater for unequal ratio CT's, the scheme can be energized from either one or two separate sets of main current transformers. The criteria of double feature operation before tripping can be maintained by the provision of two sets of ratio matching interposing CT's per circuit.

When multi-contact tripping relays are used, these are also duplicated, one being energized from each discriminating relay; the contacts of the tripping relay are then series-connected in pairs to provide tripping outputs.

Separate tripping relays, each controlling one breaker only, are usually preferred. The importance of such relays is then no more than that of normal circuit protection, so no duplication is required at this stage. Not least among the advantages of using individual tripping relays is the simplification of trip circuit wiring so achieved, as compared with taking all trip circuits associated with a given bus section through a common multi-contact tripping relay.

In double bus gear, a separate protective system is applied to each section of each bar; an overall check system is provided, covering all sections of both bars.

The separate zones are arranged to overlap the bus section switches, so that a fault on the section switch trips both the adjacent zones. This has sometimes been avoided in the past by giving the section switch a time advantage; the section switch is tripped first and the remaining breakers delayed by 0.5 seconds. Only the zone on the faulty side of the section switch will remain operated and trip, the other zone resetting and retaining that section in service. This gain, applicable only to the very infrequent section switch faults, is obtained at the expense of seriously delaying the bus protection for all other faults. This practice is therefore not generally favoured. Some variations are dealt with later under the more detailed scheme descriptions.

There are many combinations possible, but the essential principle is that no single accidental incident of a secondary nature shall be capable of causing an unnecessary trip of a bus section.

Desirable as the security against mis-tripping may be, it is achieved only by increasing the amount of equipment which is required to function to complete an operation; this inevitably increases the statistical risk that a needed tripping operation may fail. Such a failure, leaving aside the

question of consequential damage, may result in disruption of the power system to an extent as great, or greater, than would be caused by an unwanted trip. The relative risk of failure of this kind may be slight, but it has been thought worthwhile in some instances to provide a guard in this respect as well.

Security of both stability and operation is obtained by providing three independent discriminating channels, the trip outlets of which are connected in series and in pairs, as shown in Figure 15.1.

Three channels, X, Y and Z, form three independent trip circuits,  $X + Y$ ,  $Y + Z$  and  $Z + X$ . This means that any kind of failure can occur in any one channel without prejudicing either stability or ability to operate for the scheme as a whole.

It would seem that the use of this principle must increase as stations become larger and systems more heavily loaded.

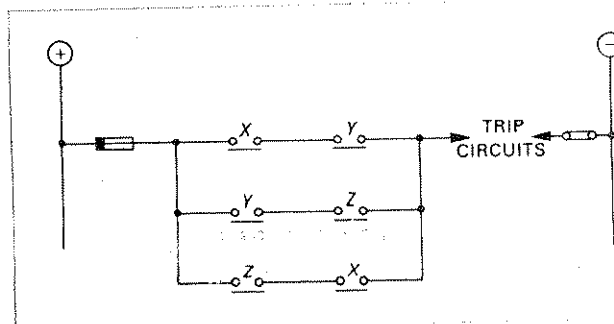


Figure 15.1 Two-out-of-three principle.

## 15.4

TYPE OF PROTECTIVE SYSTEMS

A number of protective systems have been devised:

- System protection used to cover busbars.
- Frame-earth protection.
- Differential protection.
- Phase comparison protection.
- Directional locking protection.

Of these, (a) is suitable for small stations only, while (d) and (e) are largely obsolete.

Detailed discussion of types (b) and (c) occupies most of this chapter.

Early forms of biased differential protection for busbars, such as versions of 'Translay' protection and also a scheme using harmonic restraint, were superseded years ago by unbiased high impedance differential protection.

The relative simplicity of the latter, and more importantly the relative ease with which its performance can be calculated, have ensured its success for many years since, and no doubt many years to come.

But more recently the advances in semiconductor technology, coupled with a more pressing need to be able to accommodate CT's of unequal ratio, have led to the re-introduction of biased schemes, generally using static relay designs, particularly for the most extensive and onerous applications.

The frame-earth protection system continues to serve for many of the smallest busbar installations.

### 15.4.1

#### System protection

A system protection that includes overcurrent or distance systems will inherently give protection cover to the busbars. Overcurrent protection will only be applied to relatively simple distribution systems, or as a back-up protection, set to give a considerable time delay. Distance protection will provide cover with its second zone.

In both cases, therefore, the busbar protection so obtained is slow and suitable only for non-exacting conditions.

The only exception is the case of a mesh-connected station, in which the current transformers are located at the circuit breakers. Here, the busbars are included, in sections, in the individual zones of the main circuit protection, whether this is of unit type or not. In the special case when the current transformers are located on the line side of the mesh, the circuit protection will not cover the busbars in the instantaneous zone and separate busbar protection, known as mesh-corner protection, is generally used.

## 15.5

### 15.5.1

#### Frame-earth protection with single busbar

This is purely an earth fault system, and, in principle, involves simply measuring the fault current flowing from the switchgear frame to earth. To this end a current transformer is mounted on the earthing conductor and is used to energize a simple instantaneous relay as shown in Figure 15.2.

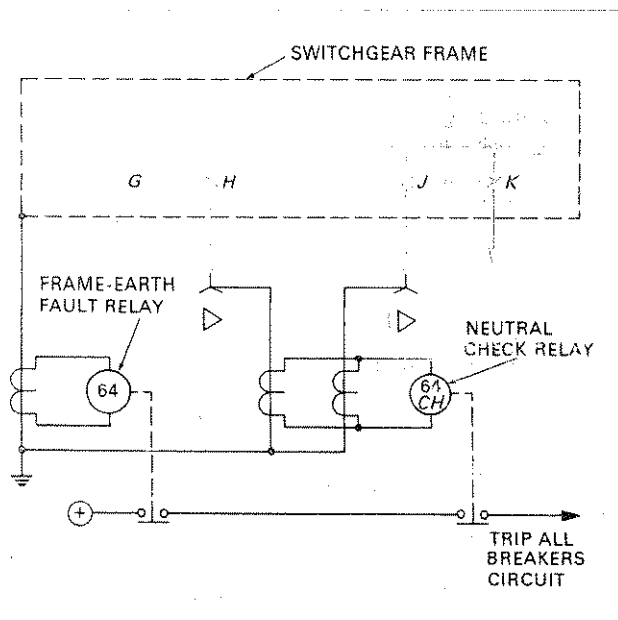


Figure 15.2 Single zone frame-earth protection.

No other earth connections of any type, including incidental connections to structural steelwork, should be present. This requirement is so that:

- The principal earth connection and current transformer is not shunted, thereby raising the effective setting. This is not usually of much consequence.
- Earth current flowing to a fault elsewhere on the system cannot flow into or out of the switchgear frame via two earth connections, as this might lead to a spurious operation.

The switchgear must be insulated as a whole, usually by standing it on concrete. Care must be taken that the foundation bolts do not touch the steel reinforcement; sufficient concrete must be cut away at each hole to permit grouting-in with no risk of touching metalwork. The insulation to earth finally achieved will not be high, a value of 10 ohms being satisfactory.

When planning the earthing arrangements of a frame-leakage scheme, the use of one common electrode for both the switchgear frame and the power system neutral point is preferred, because the fault path would otherwise include the two earthing electrodes in series. If either or both of these are of high resistance or have inadequate current

carrying capacity, the fault current may be limited to such an extent that the protective gear becomes inoperative. In addition, if the electrode earthing the switchgear frame is the offender, the potential of the frame may be raised to a dangerous value. The use of a common earthing electrode of adequate rating and low resistance ensures sufficient current for scheme operation and limits the rise in frame potential. When the system is resistance earthed, the earthing connection from the switchgear frame is made between the bottom of the earthing resistor and the earthing electrode.

Figure 15.3 illustrates why a lower limit of 10 ohms insulation resistance between frame and earth is necessary. Under external fault conditions, the current  $I_1$  flows through the frame-leakage current transformer. If the insulation resistance is too low, sufficient current may flow to operate the frame-leakage relay, and, as the check feature is unrestricted, this will also operate to complete the trip circuit. The earth resistance between the earthing electrode and true earth is seldom greater than one ohm, so with 10 ohms insulation resistance the current  $I_1$  is limited to 10% of the total earth fault current  $I_1$  and  $I_2$ . For this reason, the recommended minimum setting for the scheme is about 30% of the minimum earth fault current.

All cable glands must be insulated, to prevent the circulation of spurious current through the frame and earthing system by any voltages induced in the cable sheath. Preferably, the gland insulation should be provided in two layers or stages, with an interposing layer of metal, to facilitate the testing of the gland insulation. A test level of 5 kV from each side is suitable.

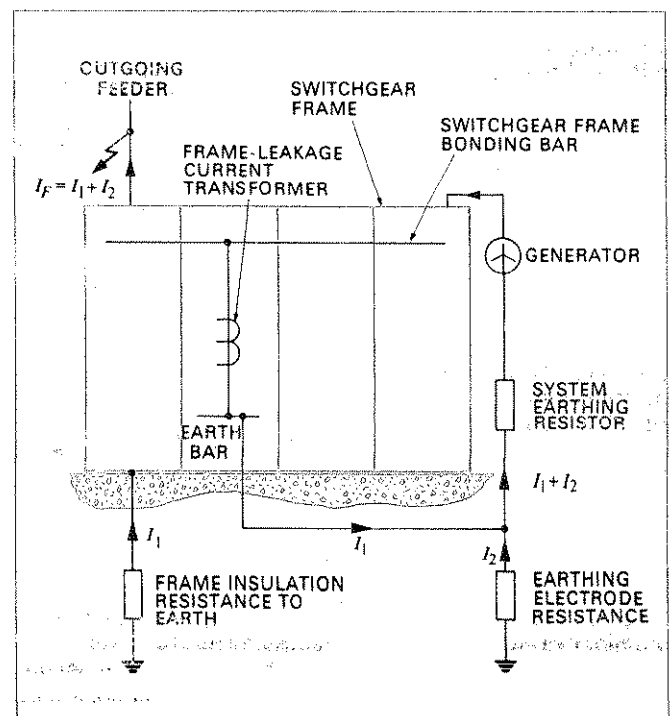


Figure 15.3 Current distribution for external fault.

### 15.5.2

#### Frame-earth protection with divided busbars

Section 15.5.1 covers the basic requirements for a system to protect a switchgear equipment as a whole. When the busbar is divided into sections, these can be protected separately, provided the frame is also sub-divided, the sections mutually insulated, and each provided with a separate earth conductor, current transformer and relay.

Ideally, the section switch should be treated as a separate zone, as shown in Figure 15.4, and provided with either a separate relay or two secondaries on the frame-leakage current transformer, with an arrangement to trip both adja-

cent zones. The individual zone relays trip their respective zone and the section switch.

If it is inconvenient to insulate the section switch frame on one side, this switch may be included in that zone. It is then necessary to intertrip the other zone after approximately 0.5 seconds if a fault persists after the zone including the section switch has been tripped. The arrangement usually applied for this busbar installation is shown in Figure 15.5.

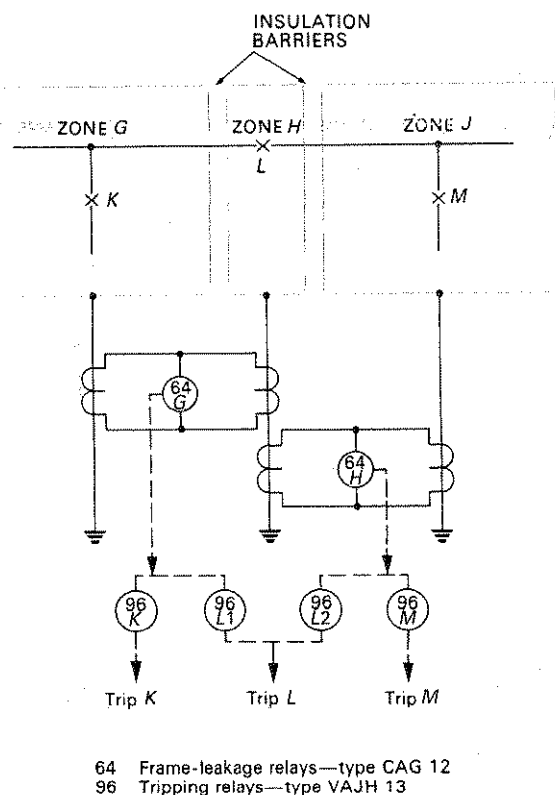


Figure 15.4 Three zone frame-earth scheme.

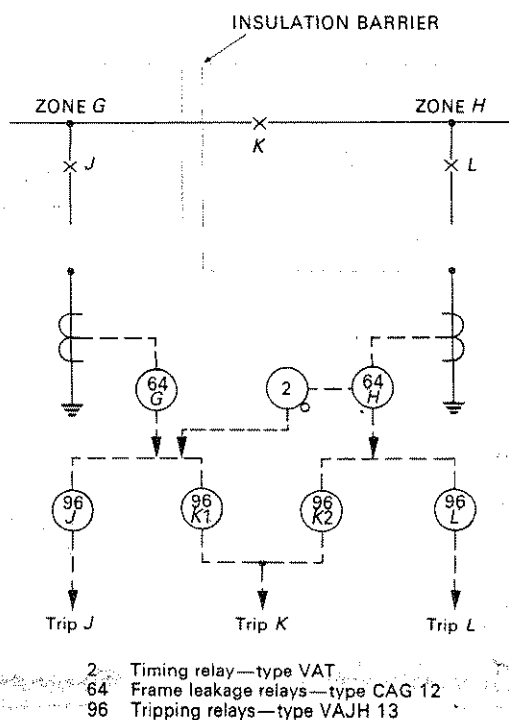


Figure 15.5 Frame-earth scheme: bus section breaker insulated on one side only.

For the above schemes to function it is necessary to have at least one infeed or earthed source of supply, and in the latter case it is essential that this source of supply be connected to the side of the switchboard not containing the section switch. Further, if possible, it is preferable that an earthed source of supply be provided on both sides of the switchboard, in order to ensure that any faults that may develop between the insulating barrier and the section switch will continue to be fed with fault current after the isolation of the first half of the switchboard, and thus allow the fault to be removed. Of the two arrangements, the first is the one normally recommended, since it provides instantaneous clearance of busbar faults on all sections of the switchboard.

### 15.5.3

#### Frame-earth scheme for double bus station

It is not generally feasible to separate by insulation the metal enclosures of the main and auxiliary busbars. Protection is generally provided, therefore, as for single bus installations, but with the additional feature that circuits connected to the auxiliary bus are tripped for all faults, as shown in Figure 15.6.

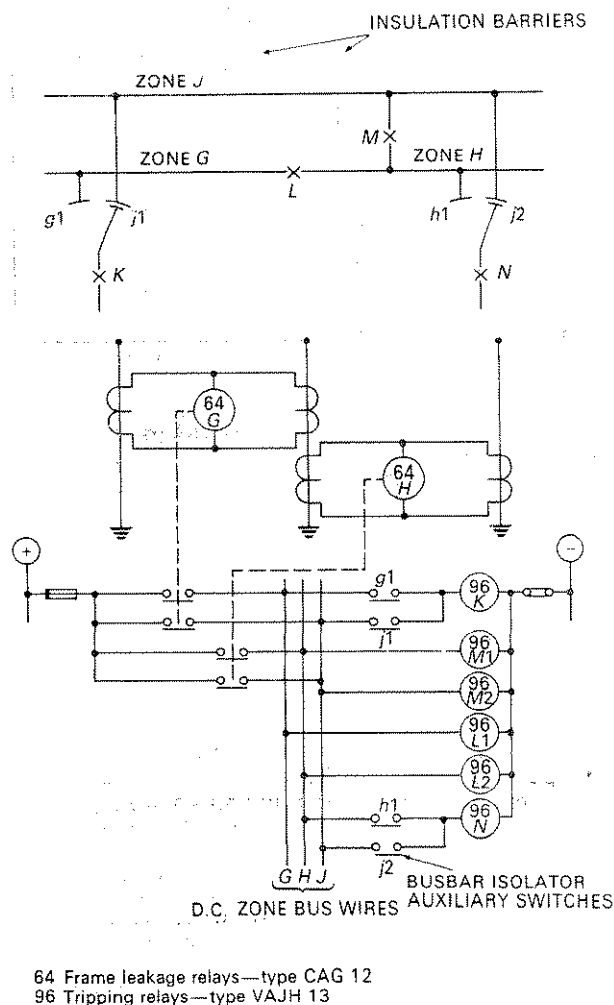


Figure 15.6 Frame-earth scheme for duplicate busbars.

### 15.5.4

#### Check system for frame-earth protection

On all but the smallest equipments, a check system should be provided to guard against such contingencies as operation being caused by mechanical shock or mistakes made by personnel. Faults in the low voltage auxiliary wiring

must also be prevented from causing operation by passing current to earth through the switchgear frame. A useful check is provided by a relay energized by the system neutral current, or residual current. If the neutral check cannot be provided, the frame-earth relays should have a short time delay.

When a check system is used, all relays can be of the nominally instantaneous class with a fault setting of 30% of the minimum earth fault current and an operating time, with a fault current of five times setting, of 15 milliseconds or less.

Figure 15.7 shows a frame-leakage scheme for a metalclad switchgear installation similar to that shown in Figure 15.4 and incorporating a neutral current check obtained from a suitable zero sequence current source, such as that shown in Figure 15.2.

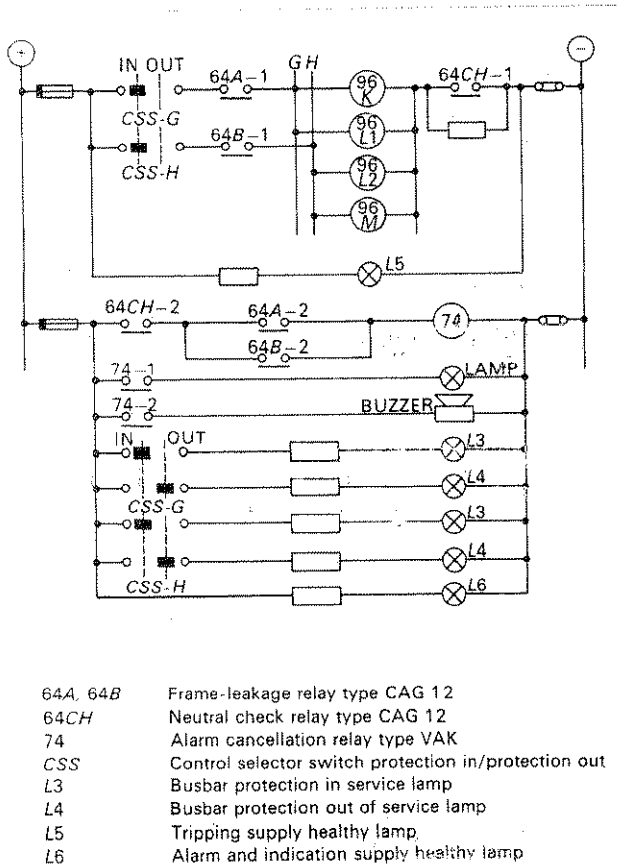


Figure 15.7 Typical tripping and alarm circuits for a frame-leakage scheme.

The protective relays used for the discriminating and check functions are of the attracted armature type, with two normally open self reset contacts. The current settings are adjustable in seven equal steps between 20 and 80 per cent of rated current, and an operating time of 10 milliseconds at 5 times the current setting is obtained.

The tripping circuits cannot be completed unless both the discriminating and check relays operate; this is because the discriminating and check relay contacts are connected in series. The tripping relays are of the attracted armature type, with four pairs of normally open hand reset contacts, and an operating time of 10 milliseconds at rated voltage.

It is usual to supervise the satisfactory operation of the protective scheme with audible and visual alarms and indications for the following:

- Busbar faults.
- Busbar protection in service.
- Busbar protection out of service.
- Tripping supply healthy.
- Alarm supply healthy.

To enable the protective equipment of each zone to be taken out of service independently during maintenance periods, isolating switches—one switch per zone—are provided in the trip supply circuits and an alarm cancellation relay is used.

## 15.6

### DIFFERENTIAL PROTECTION

#### 15.6.1

##### Basic principles

The Merz-Price principle is applicable to a multi-terminal zone such as a busbar. The principle is a direct application of Kirchhoff's first law. Usually, the circulating current arrangement is used, in which the current transformers and interconnections form an analogue of the busbar and circuit connections. A relay connected across the CT bus wires represents in the analogue a fault path in the primary system and hence is not energized until a fault occurs on the busbar; it then receives an input which, in principle at least, represents the fault current.

The scheme may consist of a single relay connected to the bus wires which connect in parallel all the current transformers, one set per circuit, associated with a particular zone, as shown in Figure 15.8. This will give earth fault protection for the busbar, which has often been thought to be adequate.

Phase fault protection can be obtained by connecting the current transformers as a balancing group for each phase and providing a three-element relay, as shown in Figure 15.9.

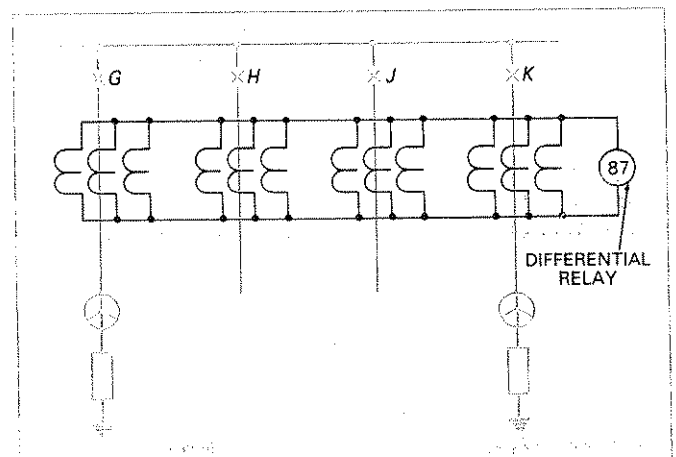


Figure 15.8 Basic circulating current scheme (earth fault protection only).

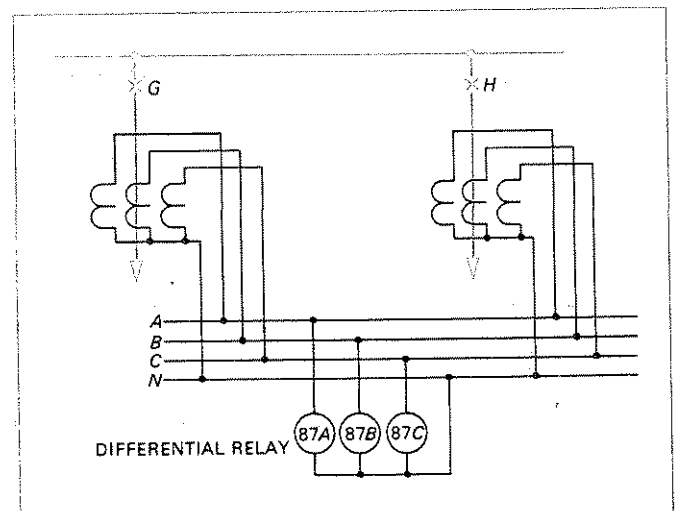


Figure 15.9 Phase and earth fault circulating current scheme using three-element relay.

The phase and earth fault settings are identical, and this scheme is recommended for its ease of application and good performance.

### 15.6.2

#### Summation schemes

By using current transformers of different ratios, for example 300/1, 400/1 and 500/1 in each three-phase group, connected in parallel and interconnected between groups by two bus wires only, a response is obtained to all types of fault, earth fault settings being low and phase fault settings higher, as shown in Figure 15.10.

This scheme is therefore suitable for resistance earthed systems and also reduces costs by lowering the number of bus wires, auxiliary switches and relay elements as compared with the conventional phase-by-phase scheme of Figure 15.9.

An alternative arrangement to that above is obtained by using current transformers of equal ratio but cross-connecting two of them and taking a centre tap from the third, as shown in Figure 15.11. In this way it is possible to obtain a closer range of fault settings than in the previous scheme. For this reason the arrangement is sometimes used to provide a two-wire phase and earth fault scheme for solidly earthed power systems in which phase and earth fault current levels are of the same order.

This simplification is made at the expense of providing much larger current transformers, since the relay setting voltage will be based on the resistance of the full CT winding, while the half winding must provide a suitable multiple of this setting voltage, for reasons discussed in Section 15.7.1. A similar consideration applies to the former scheme with unequal CT ratios.

### 15.6.3

#### Differential protection for sectionalized and duplicate busbars

Each section of a divided bus is provided with a separate circulating current system. The zones so formed are overlapped across the section switches, so that a fault on the latter will trip the two adjacent zones. This is illustrated in Figure 15.12.

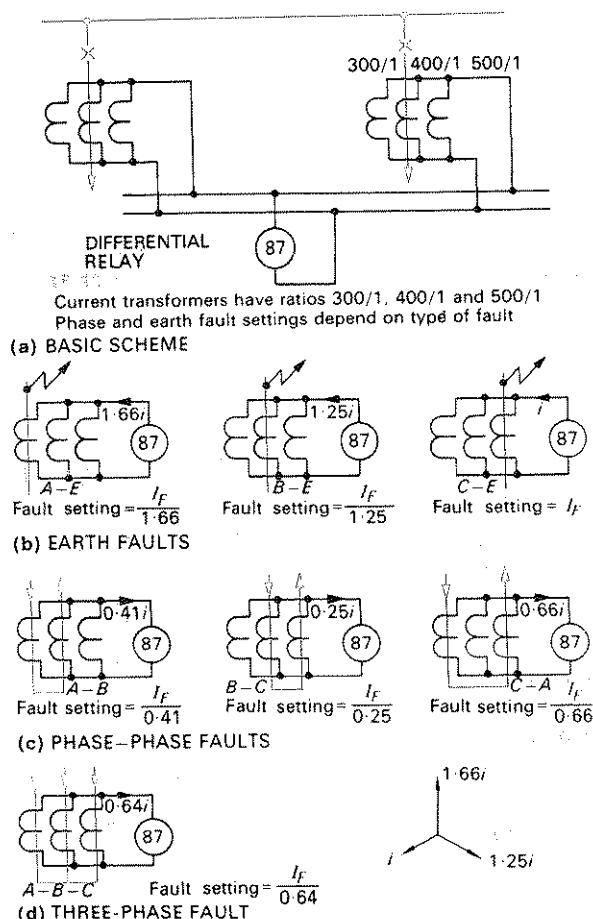


Figure 15.10 Phase and earth fault circulating current scheme using single element relay and current transformers with different ratios in each phase.

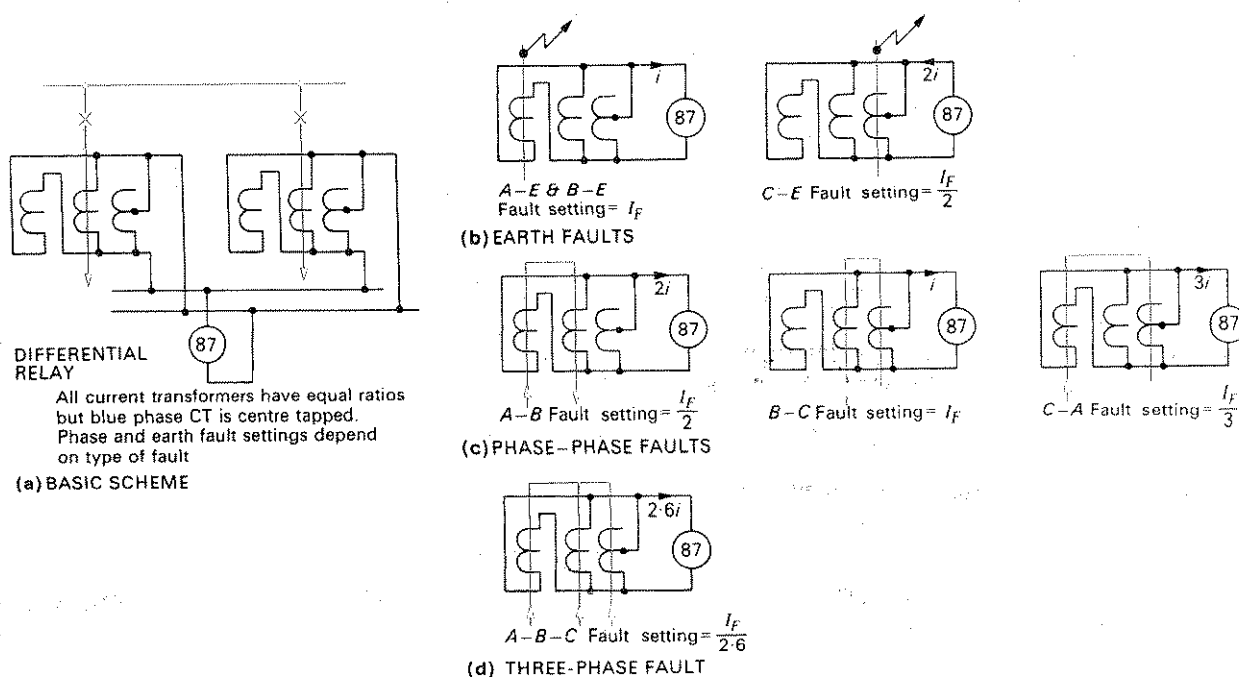


Figure 15.11 Phase and earth fault circulating current scheme: alternative summation arrangement using single element relay and equal ratio current transformers.

Tripping two zones for a section switch fault can be avoided by giving this switch a time advantage; that is, by delaying the other breakers by 0.5 seconds. The bus protection is made slower by this technique; this drawback must be weighed against the better discrimination obtained on the rare occurrence of a section switch fault. In the majority of cases instantaneous operation will be preferred.

For double bus installations, the two bars will be treated as separate zones. The auxiliary bar zone will overlap the appropriate main bar zone at the bus coupler.

Since any circuit may be transferred from one bar to the other by isolator switches, the latter must also carry auxiliary contacts to transfer the circuit current transformers between zones. The breaker tripping circuit, or the individual trip relay, must also be switched to the appropriate zone.

The above switching operations should be performed by 'early make' and 'late break' auxiliary switches on the busbar isolators, in order to ensure that when the isolators are closing, the auxiliary switches make before the main contacts of the isolator, and that when the isolators are opened, their main contacts part before the auxiliary switches open. The result is that the secondary circuits of the two zones concerned are briefly paralleled while the circuit is being transferred; these two zones have in any case been united through the circuit isolators during the transfer operation.

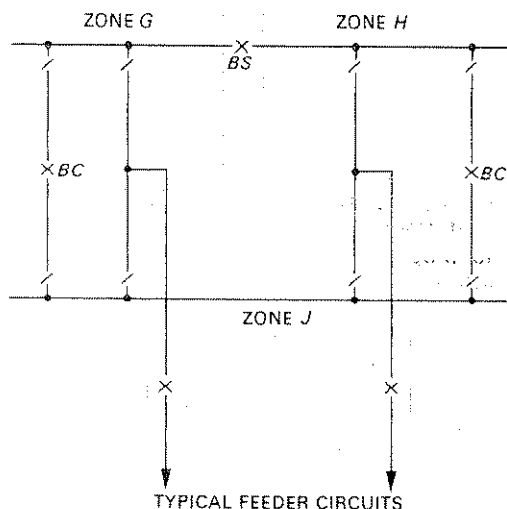


Figure 15.12 Zones of protection for double bus station.

## 15.7

### 15.7.1 Stability

The incidence of fault current with an initial unilateral transient component causes an abnormal build-up of flux in a current transformer, as described in Sections 5.3.11 and 5.3.12. When through-fault current traverses a zone protected by a differential system, the transient flux produced in the current transformers is not detrimental as long as it remains within the substantially linear range of the magnetizing characteristic. With fault current of appreciable magnitude and long transient time constant, the flux density will pass into the saturated region of the characteristic; this will not in itself produce a spill output from a pair of balancing current transformers provided that

these are identical and equally burdened. A group of current transformers, though they may be of the same design, will not be completely identical, but a more important factor is inequality of burden. In the case of a differential system for a busbar, an external fault may be fed through a single circuit, the current being supplied to the busbar through all other circuits. The faulted circuit is many times more heavily loaded than the others and the corresponding current transformers are likely to be heavily saturated, while those of the other circuits are not. Severe unbalance is therefore probable, which, with a relay of normal burden, could exceed any acceptable current setting. For this reason such systems were at one time always provided with a time delay. This practice is, however, no longer necessary.

It is not feasible to calculate the spill current which may occur, but, fortunately, this is not necessary; an alternative approach provides both the necessary information and the technique required to obtain a high performance.

A circulating current system can be represented by an equivalent circuit, as in Figure 15.13.

The current transformers are replaced in the diagram by ideal current transformers feeding an equivalent circuit that represents the magnetizing losses and secondary winding resistance, and also the resistance of the connecting leads. These circuits can then be interconnected as shown, with a relay connected to the junction points to form the complete equivalent circuit.

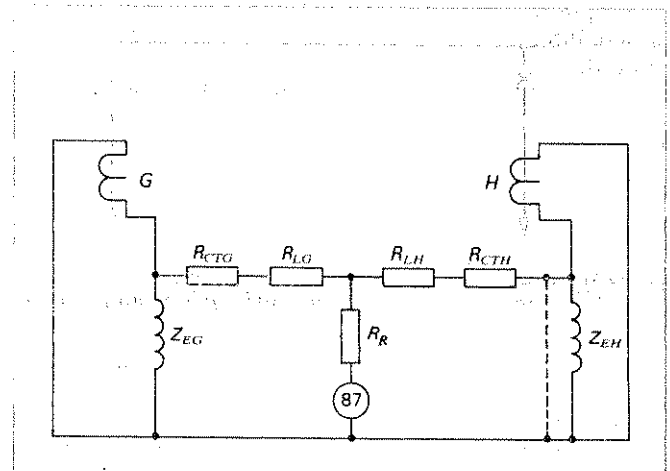


Figure 15.13 Equivalent circuit of circulating current system.

Saturation has the effect of lowering the exciting impedance, and is assumed to take place severely in current transformer H until, at the limit, the shunt impedance becomes zero and the CT can produce no output. This condition is represented by a short circuit, shown in broken line, across the exciting impedance. It should be noted that this is not the equivalent of a physical short circuit, since it is behind the winding resistance  $R_{CTH}$ .

If current transformer G, because of its higher output or lower load, as discussed above, is not saturated, it will drive the secondary fault current  $I_f$  through the total circuit burden, including  $R_{LH}$  and  $R_{CTH}$ .

Applying the Thévenin method of solution, the voltage developed across the relay will be given by:

$$V_f = I_f(R_{LH} + R_{CTH}) \quad \dots \text{Equation 15.1}$$

The current through the relay is given by:

$$I_R = \frac{V_f}{R_R + R_{LH} + R_{CTH}} = \frac{I_f(R_{LH} + R_{CTH})}{R_R + R_{LH} + R_{CTH}} \quad \dots \text{Equation 15.2}$$

If  $R_R$  is small,  $I_R$  will approximate to  $I_f$ , which is unacceptable. On the other hand, if  $R_R$  is large  $I_R$  is reduced. Equation 15.2 can be written, with little error, as follows:

$$I_R = \frac{V_f}{R_R} = \frac{I_f(R_{LH} + R_{CTH})}{R_R} \quad \dots \text{Equation 15.3}$$

or alternatively:

$$I_R R_R = V_f = I_f(R_{LH} + R_{CTH}) \quad \dots \text{Equation 15.4}$$

It is clear that, by increasing  $R_R$ , the spill current  $I_R$  can be reduced below any specified relay setting.  $R_R$  is frequently increased by the addition of a series-connected resistor which is known as the stabilizing resistor.

It can also be seen from Equation 15.4 that it is only the voltage drop in the relay circuit at setting current that is important. The relay can be designed as a voltage measuring device consuming negligible current; provided its setting voltage exceeds the value  $V_f$  of Equation 15.4 the system will be stable. In fact, the setting voltage need not exceed  $V_f$ , since the derivation of Equation 15.4 involves an extreme condition of unbalance between the  $G$  and  $H$  current transformers which is not completely realized. So a safety margin is built-in if the voltage setting is made equal to  $V_f$ .

It is necessary to realize that the value of  $I_f$  to be inserted in Equation 15.4 is the complete function of the fault current and the spill current  $I_R$  through the relay, in the limiting condition, will be of the same form. If the relay requires more time to operate than the effective duration of the d.c. transient component, or has been designed with special features to block the d.c. component, then this factor can be ignored and only the symmetrical value of the fault current need be entered in Equation 15.4. If the relay setting voltage,  $V_S$ , is made equal to  $V_f$ , that is,  $I_f(R_L + R_{CT})$ , an inherent safety factor of the order of two will exist. In the case of a faster relay, capable of operating in one cycle and with no special features to block the d.c. component, it is the r.m.s. value of the first offset wave which is significant. This value, for a fully offset waveform with no d.c. decrement, is  $\sqrt{3}I_f$ . If settings are then chosen in terms

of the symmetrical component of the fault current, the  $\sqrt{3}$  factor which has been ignored will take up most of the basic safety factor, leaving only a very small margin.

Finally, if a truly instantaneous relay were used, the relevant value of  $I_f$  would be the maximum offset peak. In this case, the factor has become less than unity, possibly as low as 0.7. It is therefore possible to rewrite Equation 15.4 as:

$$I_{SL} = \frac{K \times V_S}{R_L + R_{CT}} \quad \dots \text{Equation 15.5}$$

where  $I_{SL}$  = stability limit of the scheme

$V_S$  = relay circuit voltage setting

$R_L + R_{CT}$  = lead + CT winding resistance  
(most onerous case)

$K$  = factor depending on the relay design  
(ranging from 0.7 to 2.0)

It remains to be shown that the setting so chosen is suitable.

The current transformers will have an excitation curve which has not so far been related to the relay setting voltage, the latter being equal to the maximum nominal voltage drop across the lead loop and the CT secondary winding resistance, with the maximum secondary fault current flowing through them. Under in-zone fault conditions it is necessary for the current transformers to produce sufficient output to operate the relay. This will be achieved provided the CT knee-point voltage exceeds the relay setting. In order to cater for errors, it is usual to specify that the current transformers should have a knee-point e.m.f. of at least twice the necessary setting voltage; a higher multiple is of advantage in ensuring a high speed of operation.

## 15.7.2

### Effective setting or primary operating current

The minimum primary operating current is a further criterion of the design of a differential system. The secondary effective setting is the sum of the relay minimum operating current and the excitation losses in all parallel-connected current transformers, whether carrying primary current or not. This summation should strictly speaking be vectorial, but is usually done arithmetically. It can be expressed as:

$$I_R = I_S + nI_{ES} \quad \dots \text{Equation 15.6}$$

where  $I_R$  = effective setting

$I_S$  = relay circuit setting current

$I_{ES}$  = CT excitation current at relay setting voltage.

$n$  = number of parallel-connected current transformers.

Having established the relay setting voltage from stability considerations, as shown in Section 15.7.1, and knowing the excitation characteristic of the current transformers, the effective setting can be computed. The secondary setting is converted to the primary operating current by multiplying by the turns ratio of the current transformers.

The operating current so determined should be considered in terms of the conditions of the application.

For a phase and earth fault scheme the setting can be based on the fault current to be expected for minimum plant and maximum system outage conditions. However, it should be remembered that:

a. Phase to phase faults give only 86% of the three-phase fault current.

b. Fault arc resistance and earth path resistance reduce fault currents somewhat.

c. A reasonable margin should be allowed to ensure that relays operate quickly and decisively.

It is desirable that the primary effective setting should not exceed 30% of the prospective minimum fault current.

In the case of a scheme exclusively for earth fault protection, the minimum earth fault current should be considered, taking into account any earthing impedance that might be present as well. Furthermore, in the event of a double phase to earth fault, regardless of the interphase currents, only 50% of the system e.m.f. is available in the earth path, causing a further reduction in the earth fault current. The primary operating current must therefore be not greater than 30% of the minimum single-phase earth fault current.

In order to achieve high speed operation, it is desirable that settings should be still lower, particularly in the case of the solidly earthed power system. The transient component of the fault current in conjunction with unfavourable residual flux in the CT can cause a high degree of saturation and loss of output, possibly leading to a delay of several cycles additional to the natural operating time of the element. This will not happen to any large degree if the fault current is a larger multiple of setting; for example, if the fault current is five times the scheme primary operating current and the CT knee-point e.m.f. is three times the relay setting voltage, the additional delay is unlikely to exceed one cycle.

The primary operating current is sometimes designed to exceed the maximum expected circuit load in order to reduce the possibility of false operation under load current as a result of a broken CT lead. Desirable as this safeguard may be, it will be seen that it is better not to increase the effective current setting too much, as this will sacrifice some speed; stability is, in any case, maintained by the check feature.

An overall earth fault scheme for a large distribution board may be difficult to design because of the large number of current transformers paralleled together, which may lead to an excessive setting. It may be advantageous in such a case

ZONE R

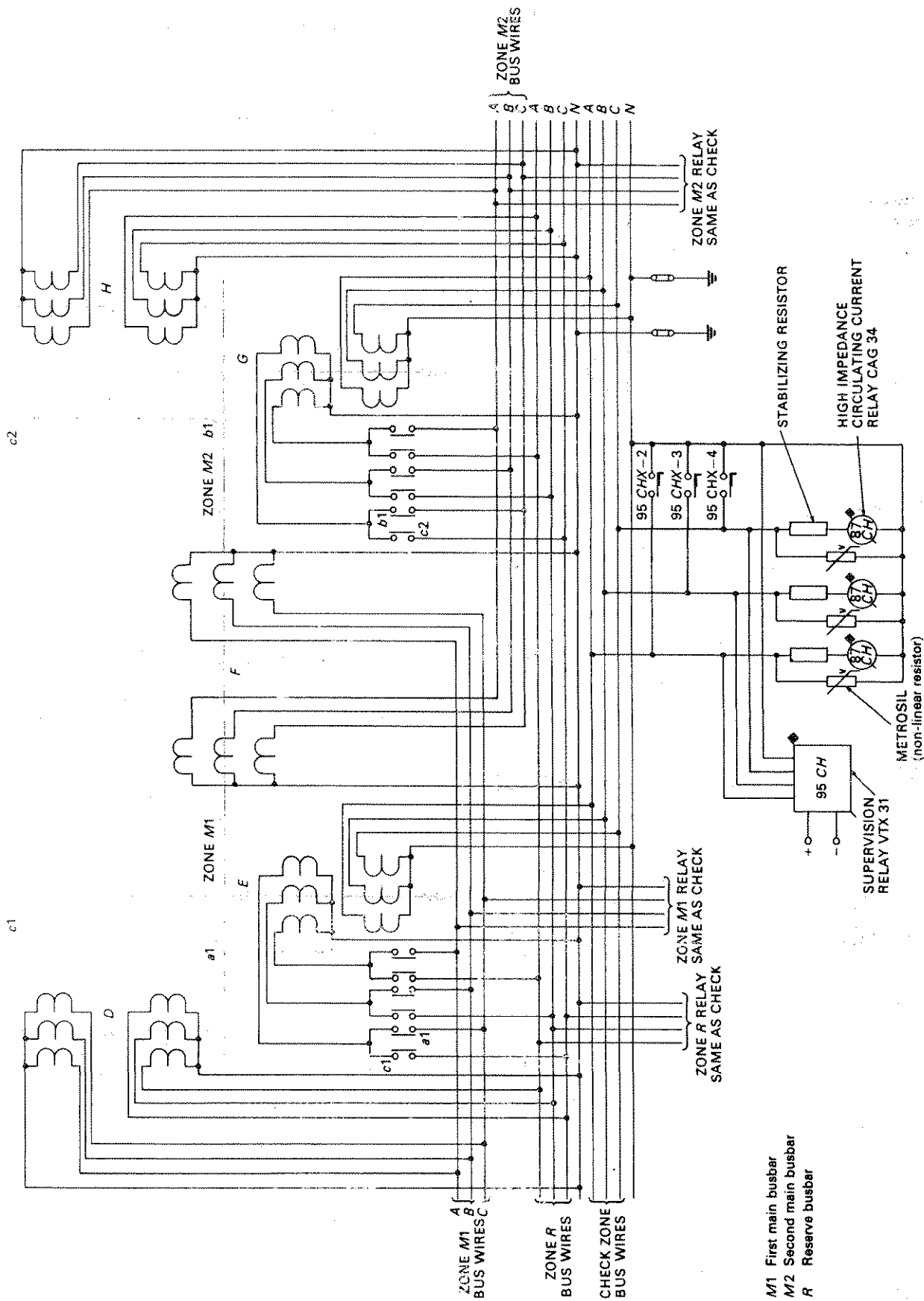


Figure 15.14 A.c. circuits for high impedance circulating current scheme for duplicate busbars.



to provide a three element phase and earth fault scheme, mainly to reduce the number of current transformers paralleled into one group.

Extra-high-voltage stations usually present no such problem. Using the voltage-calibrated relay, the current consumption can be very small. A simplification can be achieved by providing one relay per circuit, all connected to the CT paralleling buswires. This enables the trip circuits to be confined to the least area and reduces the risk of accidental operation.

### 15.7.3

#### Check feature

Schemes for earth faults only can be checked by a frame-earth system, applied to the switchboard as a whole, no subdivision being necessary.

For phase fault schemes, the check will usually be a similar type of scheme applied to the switchboard as a single overall zone. A set of current transformers separate from those used in the discriminating zones should be provided. No CT switching is required and no current transformers are needed for the check zone in bus coupler and bus section breakers.

### 15.7.4

#### Supervision of CT secondary circuits

Any interruption of a CT secondary circuit up to the paralleling interconnections will cause an unbalance in the system, equivalent to the load being carried by the relevant primary circuit. Even though this degree of spurious output is below the effective setting the condition cannot be ignored, since it is likely to lead to instability under any through fault condition.

Supervision can be carried out to detect such conditions by connecting a sensitive alarm relay across the bus wires of each zone. For a phase and earth fault scheme, an internal three-phase rectifier can be used to effect a summation of the bus wire voltages on to a single alarm element; see Figures 15.14 and 15.15.

The alarm relay is set so that operation does not occur with the protection system healthy under normal load. Subject to this proviso, the alarm relay is made as sensitive as possible; the desired effective setting is 25 primary amperes or 10% of the lowest circuit rating, whichever is the greater.

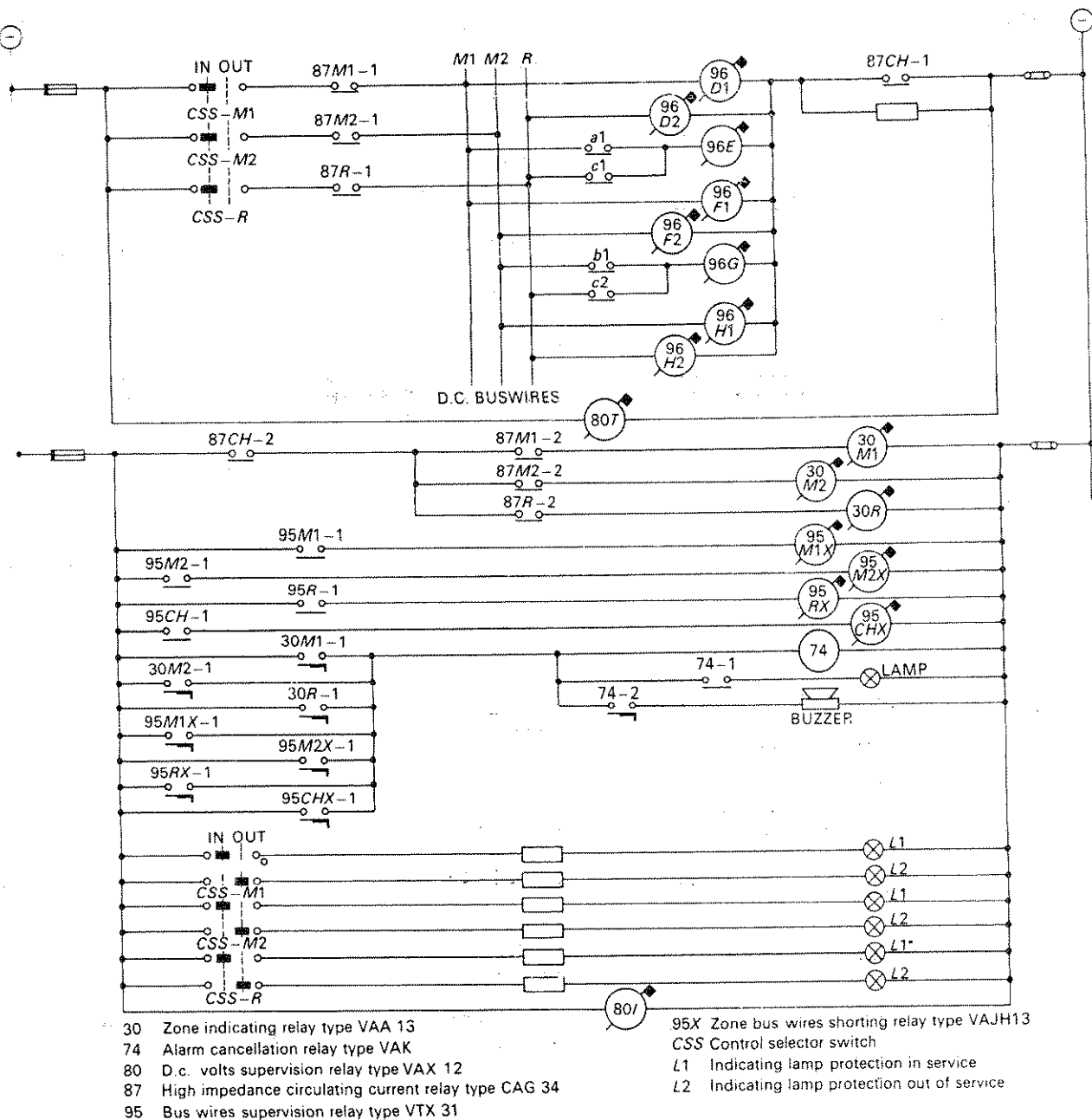


Figure 15.15 D.c. circuits for high impedance circulating current scheme.

Since a relay of this order of sensitivity is likely to operate during through faults, a time delay, typically of three seconds, is applied to avoid unnecessary alarm signals.

### 15.7.5

#### Routing of CT connections

It is shown in Equation 15.4 how the setting voltage for a given stability level is directly related to the resistance of the CT secondary leads. This should therefore be kept to a practical minimum. Taking into account the practical physical laying of auxiliary cables, the CT bus wires are best arranged in the form of a ring around the switchgear site.

In a double bus installation, the CT leads should be taken directly to the isolator selection switches. The usual routing of cables on a double bus site is as follows:

- Current transformers to marshalling kiosk.
- Marshalling kiosk to bus selection isolator auxiliary switches.
- Interconnections between marshalling kiosks to form a closed ring.

The relay for each zone is connected to one point of the ring bus wire. For convenience of cabling, the main zone relays will be connected through a multicore cable between the relay panel and the bus section switch marshalling kiosk.

The reserve bar zone and the check zone relays will be connected by a cable running to the bus coupler circuit breaker marshalling kiosk.

It is possible that special circumstances involving onerous conditions may over-ride this convenience and make connection to some other part of the ring desirable.

Connecting leads will usually be not less than 7/0.67 mm (2.5 mm<sup>2</sup>), but for large sites or in other difficult circumstances it may be necessary to use cables of, for example, 7/1.04 mm (6 mm<sup>2</sup>) for the bus wire ring and the CT connections to it. The cable from the ring to the relay need not be of the larger section.

When the reserve bar is split by bus section isolators and the two portions are protected as separate zones, it is necessary to common the bus wires by means of auxiliary contacts, thereby making these two zones into one when the section isolators are closed.

### 15.7.6

#### Summary of practical details

##### Designed stability level

For normal circumstances, the stability level should be designed to correspond to the switchgear rating; even if the available short-circuit power in the system is much less than this figure, it can be expected that the system will be developed up to the limit of rating.

##### Current transformers

Current transformers must have identical turns ratios, but a turns error of one in 400 is recognized\* as a reasonable manufacturing tolerance. Also, they should preferably be of similar design; where this is not possible the magnetizing characteristics should be reasonably matched.

The theory of a differential system is given in Section 15.7.1. The essential application formulae are repeated below.

##### Setting voltage

$$V_S \geq I_f(R_L + R_{CT})$$

where  $V_S$  = relay circuit voltage setting

$I_f$  = steady state secondary through fault current (A)

\* BS 3938: 1973, Clause 4.3.2.

$R_L$  = CT lead loop resistance to relay tapping point, for worst case (ohms)

$R_{CT}$  = resistance of CT secondary winding (ohms)

#### Knee-point voltage of current transformers

$$V_K \leq 2V_S$$

#### Effective setting (secondary)

$$I_R = I_S + nI_{es}$$

where  $I_S$  = relay circuit current setting

$I_{es}$  = CT excitation current at voltage setting

$n$  = number of current transformers in parallel.

For primary fault setting multiply  $I_R$  by the CT turns ratio.

#### Current transformer secondary rating

It is clear from Equations 15.4 and 15.6 that it is advantageous to keep the secondary fault current low; this is done by making the CT turns ratio high. It is common practice to use current transformers with a secondary rating of one ampere.

It can be shown that there is an optimum turns ratio for the current transformers; this value depends on all the application parameters but is generally about 2000/1. Although a lower ratio, for instance 400/1, is often employed, the use of the optimum ratio can result in a considerable reduction in the physical size of the current transformers.

#### Peak voltage developed by current transformers

Under in-zone fault conditions, a high impedance relay constitutes an excessive burden to the current transformers, leading to the development of a high voltage; the voltage waveform will be highly distorted but the peak value may be many times the nominal saturation voltage.

When the burden resistance is finite although high, an approximate formula for the peak voltage is:

$$V_p = 2\sqrt{2} \sqrt{V_K(V_F - V_K)} \quad \dots \text{Equation 15.7}$$

where  $V_p$  = peak voltage developed

$V_K$  = saturation voltage

$V_F$  = prospective voltage in the absence of saturation

This formula does not hold for the open circuit condition and is inaccurate for very high burden resistances that approximate to an open circuit, because simplifying assumptions used in the derivation of the formula are not valid for the extreme condition.

Another approach applicable to the open circuit secondary condition is:

$$V_p = \sqrt{2} \frac{I_f}{I_{ek}} V_K \quad \dots \text{Equation 15.8}$$

where  $I_f$  = fault current

$I_{ek}$  = exciting current at knee-point voltage

$V_K$  = knee-point voltage

Any burden connected across the secondary will reduce the voltage, but the value cannot be deduced from a simple combination of burden and exciting impedances.

These formulae are therefore to be regarded only as a guide to the possible peak voltage. With large current transformers, particularly those with a low secondary current rating, the voltage may be very high, beyond the value for which it is convenient to insulate. The voltage can be limited without detriment to the scheme by connecting in parallel with the relay a ceramic non-linear resistor having a characteristic given by:

$$V = CI^B$$

where  $C$  is a constant depending on dimensions and  $\beta$  is a constant in the range 0.2–0.25. GEC ALSTHOM Measurements schemes with 1 A current transformers use a non-linear resistor rated to carry 30 amperes for 2 seconds with a cut-off point of 900 volts r.m.s. when  $C$  is 150 and 1500 volts r.m.s. when  $C$  is 900.

The current passed by the non-linear resistor at the relay voltage setting depends on the value of  $C$ ; in order to keep the shunting effect to a minimum it is recommended to use a non-linear resistor with a value of  $C$  of 450 for relay voltages up to 175 V and one with a value of  $C$  of 900 for setting voltages up to 325 V.

### High impedance relay

Instantaneous attracted armature relays are used. Simple fast-operating relays would have a low safety factor constant in the stability Equation 15.5, as discussed in Section 15.7.1. The performance is improved by series-tuning the relay coil, thereby making the circuit resistive in effect. Inductive reactance would tend to reduce stability, whereas the action of capacitance is to block the unidirectional transient component of fault current and so raise the stability constant.

In the type CAG14 relay, a tuned element is fed from a tapped auto-transformer to provide a range of settings, for example 0.025–0.1 A. The relay is provided with a stabilizing resistor of a value calculated as indicated in Section 15.9.

The type FAC14 relay is designed to apply the limited spill voltage principle shown in Equation 15.4. A tuned element is connected via a plug bridge to a chain of resistors; the relay is calibrated in terms of voltage, the standard range of settings being 25 to 175 volts in steps of 25 volts.

The relay consumption is 0.02 A on any tap; the external Metrosil non-linear resistor referred to above increases the consumption at the highest tap setting by about 0.1 A.

The tripping circuits include the zone discriminating and check relay contacts in series, the discriminating contacts being on the positive side of the tripping relays and the check contacts with a shunt connected resistor on the negative side, thereby making spurious operation impossible.

The buswire supervision relays type VTX31, device 95, are connected in parallel with the protective relays. The type VTX relay incorporates a time delay, operating after three seconds to provide an alarm and take the faulty section out of service by short-circuiting the appropriate bus wires. This is done by means of an auxiliary attracted armature relay type VAJH13 for 1 A CTs and a VAJH23 for 5 A CTs.

Testing and maintenance facilities are provided by test links in all CT circuits and by control selector switches and isolating links in the d.c. and tripping circuits.

### 15.8.2

#### Overcurrent discrimination and high impedance checking

In double bus installations where the fault level of all circuits is high, an alternative scheme can be used which dispenses with the need for auxiliary switches in CT circuits. This scheme uses a phase and earth fault check feature of the circulating current type in conjunction with instantaneous high set overcurrent relays in all circuits.

When the circulating current relay operates, the bus coupler breaker is tripped and a timer is energized as shown in Figure 15.16. The contacts of the timer check the trip circuit of the overcurrent relays. In this way, the overcurrent relays operate discriminatively, since the timer contacts prevent tripping until the bus coupler has opened and the overcurrent relays in the healthy zone have reset.

### 15.8

#### 15.8.1

##### High impedance discrimination and checking

Figures 15.14 and 15.15 show a typical high impedance circulating current scheme for the protection of a double busbar switchgear installation.

Three discriminating zones are provided; each circuit is fitted with a three-phase set of current transformers, which are connected by isolating switches to one of the main bar zones,  $M1$  or  $M2$ , or the reserve bar zone  $R$ , according to the connection of the primary circuit. In this way, three sets of balancing bus wires are formed, the neutral bus wire being common and earthed through a removable link.

Auxiliary switch contacts are silver-plated, with two switches in parallel per phase, to minimize the risk of high contact resistance. Current transformers are also provided on each side of the bus section breaker and bus coupler breakers.

A three element type CAG34 relay, device 87, is connected to each set of bus wires to give phase and earth fault protection. The relays are fitted with external stabilizing resistors chosen to give the required stability level, and with shunting Metrosil non-linear resistors as described in Section 15.7.6.

The check feature is similar, but covers the switchboard as a single zone. Current transformers in every circuit, separate from those above, are connected to a set of bus wires and a check relay. No current transformers are required in the section and coupler breakers, and no auxiliary switches are needed.

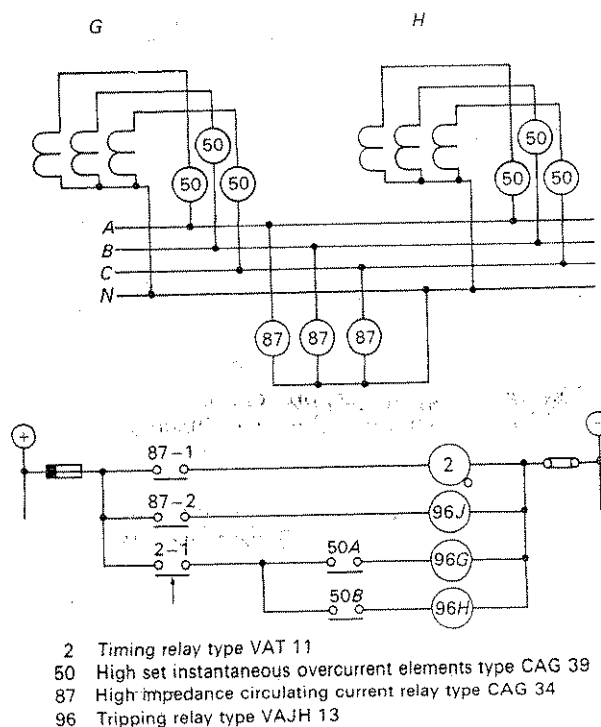


Figure 15.16 Alternative scheme using a high impedance circulating current relay with high set instantaneous overcurrent relays on a double bus station.

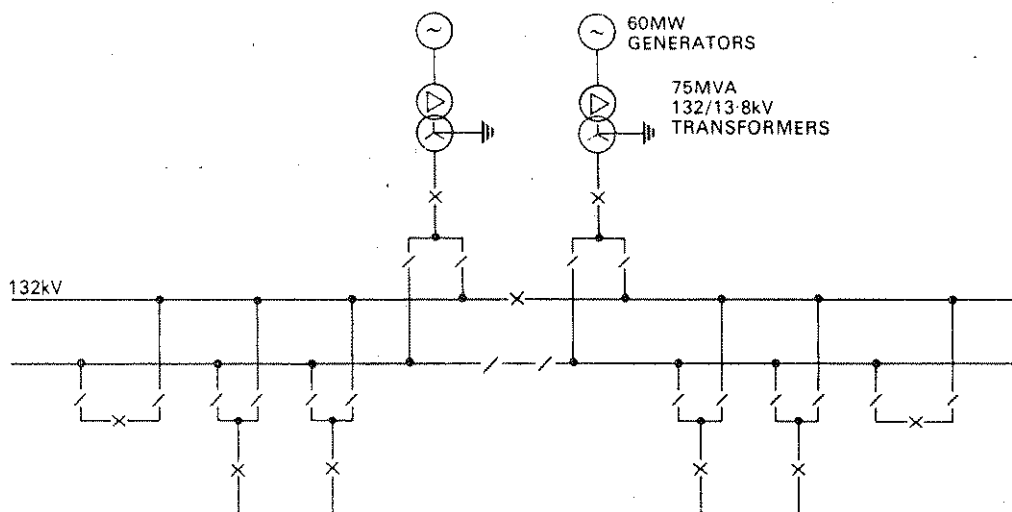


Figure 15.17 Power station layout.

## 15.9

### 15.9.1

#### Example of phase and earth fault protection

A 132kV double bus installation is shown in Figure 15.17; it is made up of two generator and four feeder circuits. The system is solidly earthed and the switchgear rating is 3500 MVA. The maximum loop resistance between the current transformers and the measuring point is 2 ohms; the current transformers have characteristics as shown in Figure 15.18, and in particular as follows:

|                      |           |
|----------------------|-----------|
| Ratio                | 500/1A    |
| Knee-point e.m.f.    | 400 volts |
| Secondary resistance | 0.7 ohms  |

A circulating current high impedance phase and earth fault scheme is to be applied.

#### Stability level

The stability level will be designed for the switchgear rating even though the initial fault power infeeds are less.

$$\text{Fault current} = \frac{3500 \times 10^6}{\sqrt{3} \times 132,000} = 15,300 \text{ A}$$

$$\begin{aligned} \text{Equivalent secondary fault current } (I_f) \\ &= \frac{15,300}{500} = 30.6 \text{ A} \end{aligned}$$

$$\begin{aligned} \text{Limiting bus wire voltage} \\ &= 30.6 (2.0 + 0.7) = 82.6 \text{ volts.} \end{aligned}$$

#### Using a type FAC34 relay

The next higher standard setting is 100 volts, which is only one quarter of the knee-point e.m.f.

At 100 volts the equivalent flux density in the CT is 100/27.2 or 3.67 kilogauss, which corresponds to

$$I_e = 0.34 \times 0.082 = 0.028 \text{ A}$$

The discriminating main zones have a maximum of five circuits, including the coupler and section breakers; the minimum number could be taken as four circuits. The reserve bar zone could have eight circuits, while the check

zone would have six. The minimum primary operating current, P.O.C., is  $500[0.03 + (4 \times 0.028)] \text{ A}$ , that is, 71 A. Compared with the generator circuit ratings of 328 A or feeder ratings of 500 A, the minimum primary operating current is low, so it would probably be considered good practice to shunt the relay with a resistor of about 100 ohms to bring the primary operating current to a value exceeding the rated loads.

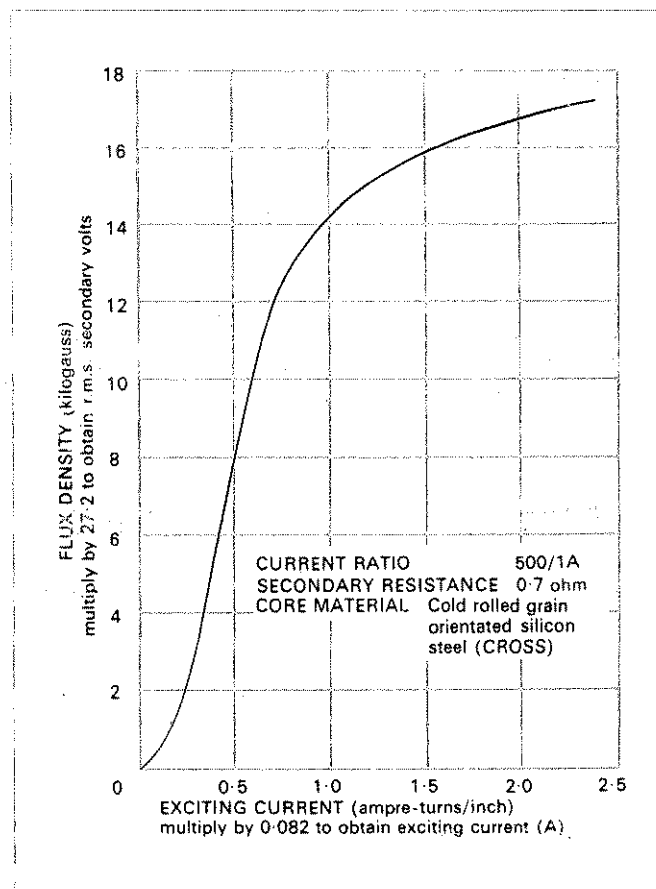


Figure 15.18 Excitation characteristic of current transformer.

#### Using a type CAG34 relay

A setting of 100 volts will be desirable as above.

The CT exciting current is  $4 \times 0.028$ , or 0.112 A. With a current setting range of 0.2–0.8 A, the 0.8 A tap setting gives:

$$\text{P.O.C.} = 500(0.112 + 0.8) = 456 \text{ A}$$

This value, compared with load ratings, may be considered to be satisfactory.

*Stabilizing resistor*

$$\text{Total relay circuit impedance} = \frac{100}{0.8} = 125 \text{ ohms.}$$

$$\text{Relay burden at setting} = 1 \text{ VA}$$

$$\text{Hence impedance} = \frac{1}{0.8^2} = 1.56 \text{ ohms.}$$

This can be neglected as compared with the total value of 125 ohms which can be specified as the value of the stabilizing resistor.

### Supervision

This should operate with an unbalance equal to 25 A or 10% of the minimum circuit rating. Taking 25 A as the value this is equivalent to 0.05 A secondary. The maximum number of circuits, eight, is in the reserve zone. The supervision relay current at setting voltage is negligible.

The initial impedance of the current transformers in the 'bottom bend' region is  $13.6/0.0082$ , or 1660 ohms. Impedance of 8 current transformers = 207 ohms.

Parallel impedance of current transformers and differential relay =  $(207 \times 125)/332 = 78 \text{ ohms}$ . Voltage drop with 0.05 A = 3.9 volts.

To provide a margin, the relay could be set to 2 volts, giving a primary operating current of  $(2/3.9) \times 25$ , or 12.8 A. In practice, this value would be tried and adopted provided the steady spill current with system load flowing did not approach the relay setting.

### 15.9.2

#### Example of earth fault protection only

A 33 kV double bus installation has a total of 20 circuits. The switchgear rating is 500 MVA and the system is earthed through a resistance rated to carry 1000 A.

Only earth fault protection is to be provided.

CT characteristics:

|                      |           |
|----------------------|-----------|
| Ratio                | 400/1 A   |
| Knee-point e.m.f.    | 250 volts |
| Secondary resistance | 0.8 ohms  |

The magnetizing characteristic may be taken to be as in Figure 15.18 except that the scale constants to be used are:

|                    |       |
|--------------------|-------|
| Ordinate (voltage) | 17.0  |
| Abscissa (current) | 0.05. |

The maximum CT lead resistance is 0.3 ohms.

$$\text{Stability level} = \frac{500 \times 10^6}{\sqrt{3} \times 33,000}$$

$$= 8760 \text{ A} = 21.9 \text{ A secondary}$$

$$\begin{aligned} \text{Limiting bus wire voltage} &= 21.9(0.8 + 0.3) \\ &= 24.1 \text{ volts} \end{aligned}$$

### Using a type FAC14 relay

Choose a tap setting of 25 volts, the knee-point e.m.f. being an adequate multiple.

At 25 volts the flux density is  $25/17$  or 1.47 kilogauss, and the exciting current is  $0.2 \times 0.05 \text{ A}$  or 0.01 A.

The reserve bar may be connected to all circuits, giving 60 current transformers in parallel for an earth fault scheme. Hence the P.O.C. =  $400[0.02 + (60 \times 0.01)] \text{ A} = 248 \text{ A}$ .

The setting should not exceed 30% of the minimum earth fault current, that is, 300 A. The above operating current may therefore be regarded as satisfactory, although with no great contingency factor if the calculation has been based on estimated CT characteristics and lead resistances.

In this case, an advantage is gained from the low settings of the type FAC14 relay.

### Using a type CAG14 relay

When a CAG14 relay is used, it should have a setting range of 0.025–0.1 A.

Using the lowest tap, the voltage drop at setting for a 1 VA burden is  $1/0.025$  or 40 volts. At 40 volts the flux density in the CT is  $40/17$  or 2.36 kilogauss, and the exciting current is  $(0.28 \times 0.05)$  or 0.014 A. Hence the P.O.C. is  $400[0.025 + (60 \times 0.014)]$  or 346 A, which is higher than required.

The next higher tap is 0.0375 A, which will give a voltage drop at setting of 26.7 V leading to a P.O.C. of  $400[0.0375 + (60 \times 0.0105)]$  or 267 A, which is within the specified limit.

### Supervision

The initial impedance of the current transformers is  $8.5/0.005$  or 1700 ohms.

The parallel impedance of 60 current transformers is  $1700/60$  or 28.3 ohms.

The impedance of the relay is  $26.7/0.0375$  or 712 ohms.

The parallel impedance of the current transformers and the differential relay is  $(28.3 \times 712)/740$  or 27.2 ohms.

The desired sensitivity is 25 primary amperes which is  $25/400$  or 0.0625 A secondary.

The voltage drop at 0.0625 A is  $(0.0625 \times 27.2)$  or 1.7 volts.

The type VTX relay can be set to 2.0 volts, giving a primary operating current of  $2.0/1.7 \times 25$  or 29.4 A. This corresponds to the extreme condition of all circuits being connected to the reserve bar. Under normal conditions fewer circuits than this will be connected into any one zone, giving a lower operating current for the supervision relay; its performance can therefore be regarded as satisfactory.

### 15.10

DIFFERENTIAL PROTECTION OF A 33 kV DOUBLE BUS INSTALLATION

#### 15.10.1

#### Use of bias in differential protection

The introduction of bias to the differential relay has the effect of reducing the requirements imposed on the current transformers.

A bias dependent on the total value of fault current is usually obtained by means of diodes which route all the secondary currents through the bias circuit. The resultant bias is proportional to the arithmetic sum of all the circuit currents, whereas the operating circuit is energized by the vector sum, as shown in Figure 15.19.

The reduction in current transformer size when bias is used is theoretically proportional to the ratio:

Relay operating current with zero bias

Relay operating current with maximum bias

A further advantage of biased protection is that it compensates for small ratio mismatch between main current transformers. This enables mixed ratio current transformers to be used with auxiliary transformers to provide ratio matching.

The principles of a check zone, zone selection and tripping arrangements and so on may be applied as for an unbiased scheme. Whereas the high impedance scheme tends to be distributed, the biased scheme has a central protection

unit. Current transformer secondary circuits are not switched directly by isolator contacts but instead by isolator repeat relays after a secondary stage of current transformation. These switching relays form a replica of the busbar within the protection and provide the complete selection logic.

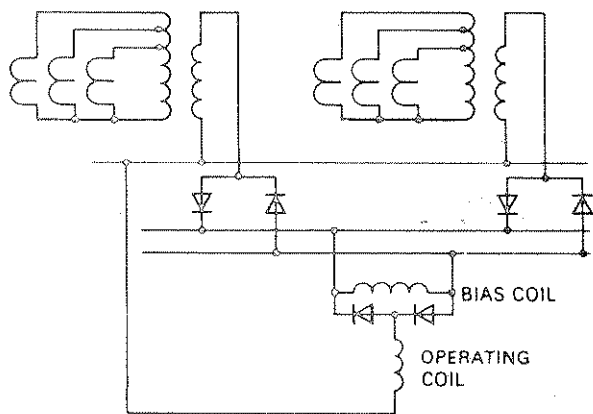


Figure 15.19 Biased differential protection for a busbar.

### 15.10.2 Stability

With some biased relays the stability is not assured by the through current bias feature alone, but is enhanced by the addition of a stabilizing resistor, having a value which may be calculated as follows.

The effective relay minimum operating current for a biased relay will be increased by the through current as follows:

$$I_R = I_S + BI_F$$

where  $B$  is the percentage restraint.

As  $I_F$  is generally much greater than  $I_S$ , the relay effective current,  $I_R = BI_F$  approximately.

From equation 15.4, the value of stabilizing resistor is given by:

$$R_R = \frac{I_F(R_{LH} + R_{CTH})}{I_R}$$

$$= \frac{R_{LH} + R_{CTH}}{B}$$

It is interesting to note that the value of the stabilizing resistance is independent of current level, and that there would appear to be no limit to the through fault stability level. This has been identified by Hodgkiss\* as 'The Principle of Infinite Stability'.

The stabilizing resistor, although lower in value than that required for the high impedance relay, still constitutes a significant burden on the current transformers during internal faults.

An alternative technique, used by the system described in Section 15.11, is to block the differential measurement during the portion of the cycle that a current transformer is saturated. If this is achieved by momentarily short circuiting the differential path, a very low burden is placed on the current transformers. In this way the differential circuit of the relay is prevented from responding to the spill current.

It must be recognized though that the use of any technique for inhibiting operation, to improve stability performance for through faults, must not be allowed to diminish the relay's ability to respond to internal faults.

\* The Behaviour of Current Transformers subjected to Transient Asymmetric Currents and the Effects on Associated Protective Relays. J. W. Hodgkiss. CIGRE Paper Number 329, Session 15-25 June 1960.

### 15.10.3

#### Effective setting or primary operating current

For an internal fault, and with no through fault current flowing, the effective setting ( $I_R$ ) is raised above the basic relay setting ( $I_S$ ) by whatever biasing effect is produced by the sum of the CT magnetizing currents flowing through the bias circuit. With low impedance biased differential schemes particularly where the busbar installation has relatively few circuits, these magnetizing currents may be relatively negligible, depending on the value of  $I_S$ .

The basic relay setting current was formerly defined as the minimum current required solely in the differential circuit to cause operation. This approach simplified analysis of performance, but was considered by some to be unrealistic as in practice any current flowing in the differential circuit must flow in at least one half of the relay bias circuit, causing the practical minimum operating current always to be higher than the nominal basic setting current.

Conversely, it needs to be appreciated that applying the later definition of relay setting current, which flows through at least half the bias circuit, the notional minimum operation current in the differential circuit alone is somewhat less, as shown in Figure 15.20(b).

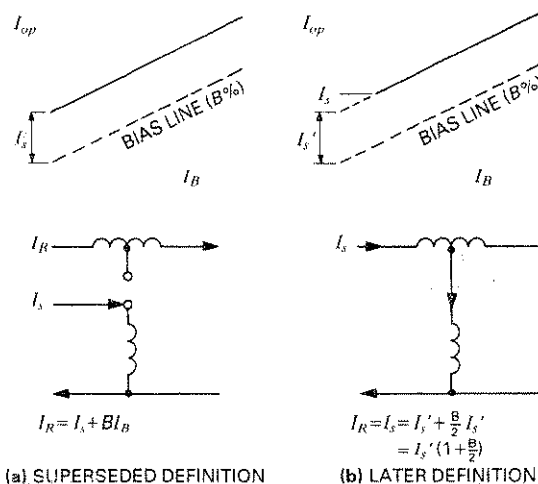


Figure 15.20 Definitions of relay setting current for biased relays

Using the definition presently applicable, the effective minimum primary operating current =  $N[I_S + B\Sigma I_{es}]$ .

Where  $N = CT$  ratio.

Unless the minimum effective operating current of a scheme has been raised deliberately to some preferred value, it will usually be determined by the check zone, when present, as the latter may be expected to involve the greatest number of current transformers in parallel.

A slightly more onerous condition may arise though, when two discriminating zones are coupled, transiently or otherwise by the closing of primary isolators.

It is generally desirable to attain an effective primary operating current that is just greater than the maximum load current, to prevent the busbar protection from operating spuriously from load current should a secondary circuit wiring fault develop. This consideration is particularly important where the check feature is either not used or is fed from common main CT's.

### 15.10.4

#### Check feature

The considerations outlined in Section 15.7.3 for high

impedance differential schemes apply, in general, to low impedance schemes also. But the controlling factor is the degree to which any check feature is required to be independent of the discriminating parts of a scheme.

For example, for some low impedance schemes only one set of main CT's is required, but it is claimed that the spirit of the checking principle is met by making operation of the protection dependent on two different criteria such as directional and differential measurements.

In another low impedance scheme, described in Section 15.11, the provision of auxiliary CT's as standard for ratio matching also provides a ready means for introducing the check feature duplication at the auxiliary CT's and onwards to the relays. This may be an attractive compromise when only one set of main CT's is available.

#### 15.10.5

##### Supervision of CT secondary circuits

In low impedance schemes the integrity of the CT secondary circuits can also be monitored in a manner similar to that for high impedance differential schemes. A current operated auxiliary relay, or element of the main protection equipment, may be applied to detect any unbalanced secondary currents and give an alarm after a time delay. For

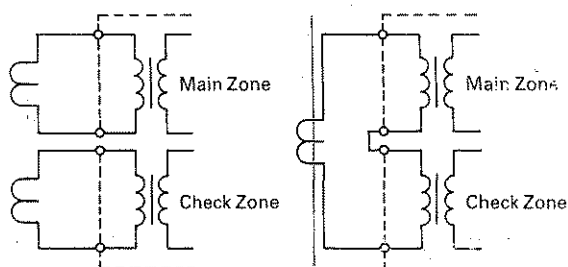


Figure 15.21 Alternative CT connections.

optimum discrimination the current setting of this supervision relay must be less than that of the main differential protection.

In modern static forms of busbar protection the supervision of the secondary circuits typically forms but a part of a comprehensive supervision facility.

#### 15.10.6

##### Routing of CT connections

It is a common modern requirement of low impedance schemes that none of the main CT secondary circuits should be switched, in the previously conventional manner, to match the switching of primary circuit isolators.

The usual solution is to route all the CT secondary circuits back to the protection panel or cubicle to auxiliary CT's. It is then the secondary circuits of the auxiliary CT's which are switched as necessary. So auxiliary CT's may be included for this function even when the ratio matching is not in question.

In static protection equipments it is undesirable to use isolator auxiliary contacts directly for the switching without some form of insulation barrier. The latter may be provided by position transducers which follow the opening and closing of the isolators.

Alternatively, a simpler arrangement may be provided on multiple busbar systems where the isolators switch the auxiliary current transformer secondary circuits via auxiliary relays within the protection. These relays form a replica of the busbar and perform the necessary logic.

It is therefore necessary to route all the current transformer secondary circuits to the relay to enable them to be connected into this busbar replica.

Some installations have only one set of current transformers available per circuit. Where the facility of a check zone is still required, this can still be achieved with the low impedance biased protection by connecting the auxiliary current transformers at the input of the main and check zones in series, as shown in Figure 15.21.

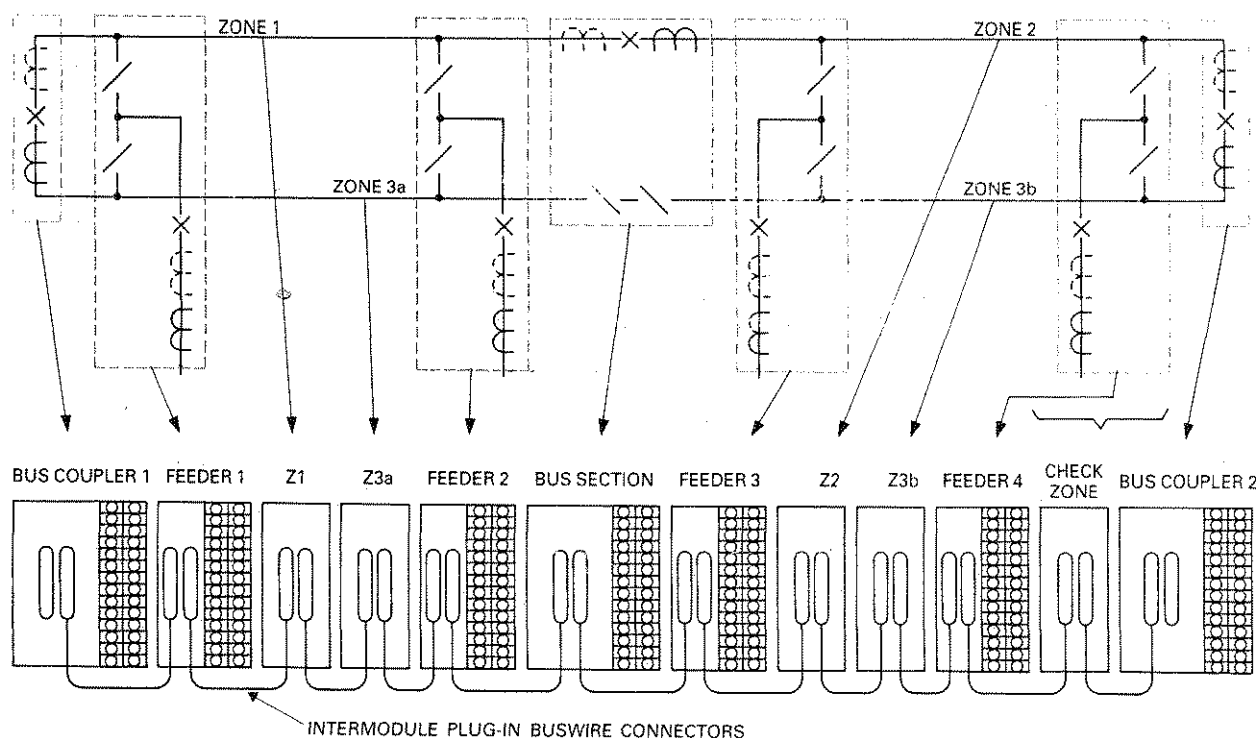


Figure 15.22 Type MBCZ busbar protection showing correlation between circuit breakers and protection modules.



The Type MBCZ scheme conforms in general to the principles outlined in Section 15.10 and comprises a system of standard modules which can be assembled to suit a particular busbar installation. Additional modules can be added at any time as the busbar is extended.

A separate module is used for each circuit breaker and also one for each zone of protection. In addition to these there is a common alarm module and a number of power supply units.

The diagram Figure 15.22 shows the correlation between the circuit breakers and the protection modules for a typical double busbar installation. In practice the modules are mounted in a multi-tier rack or cubicle, as illustrated in Figure 15.23.

For each of the module types shown there are several variations to match the various primary plant configurations. These variations are achieved by altering links on the printed circuit boards or by adding isolator repeat relays.

The modules are interconnected via a multicore cable that is plugged into the back of the modules. There are five main groups of buswires, allocated for:

- i. Protection for main busbar.
- ii. Protection for reserve busbar.
- iii. Protection for the transfer busbar. When the reserve busbar is also used as a transfer bar then this group of buswires is used.
- iv. Auxiliary connections used by the protection to combine modules for some of the more complex busbar configurations.
- v. Protection for the check zone.

One extra module, not shown in this diagram, is plugged into the multicore bus. This is the alarm module which contains the common alarm circuits and the bias resistors. The power supplies are also fed in through this module.

### 15.11.1

#### Operating principles

##### *Bias*

All zones of measurement are biased by the total current flowing to or from the busbar system via the feeders. This ensures that all zones of measurement will have similar fault sensitivity under all load conditions.

The bias is derived from the check zone and the setting resistors are housed in the alarm module as this is also common to all zones. These resistors are set to give a fixed steady state bias of 20%, with a characteristic generally as shown in Figure 15.20(b). Thus some ratio mismatch is tolerable.

##### *Stability with saturated current transformers*

The traditional method for stabilizing a differential relay is to add a resistor to the differential path. Whilst this improves stability it increases the burden on the current transformer for internal faults. The technique used in the MBCZ scheme overcomes this problem.

During a through fault one of the CT's may saturate and therefore will not provide a balancing current for the other CT's in a differential system. A differential current will therefore be produced by the unsaturated CT's. The principle used in the MBCZ design is to detect when a CT is saturated and short circuit the differential path for the portion of the cycle for which saturation occurs. The resultant spill current does not then flow through the measuring circuit and stability is assured.

This principle allows a very low impedance differential circuit to be developed that will operate successfully with relatively small CT's.

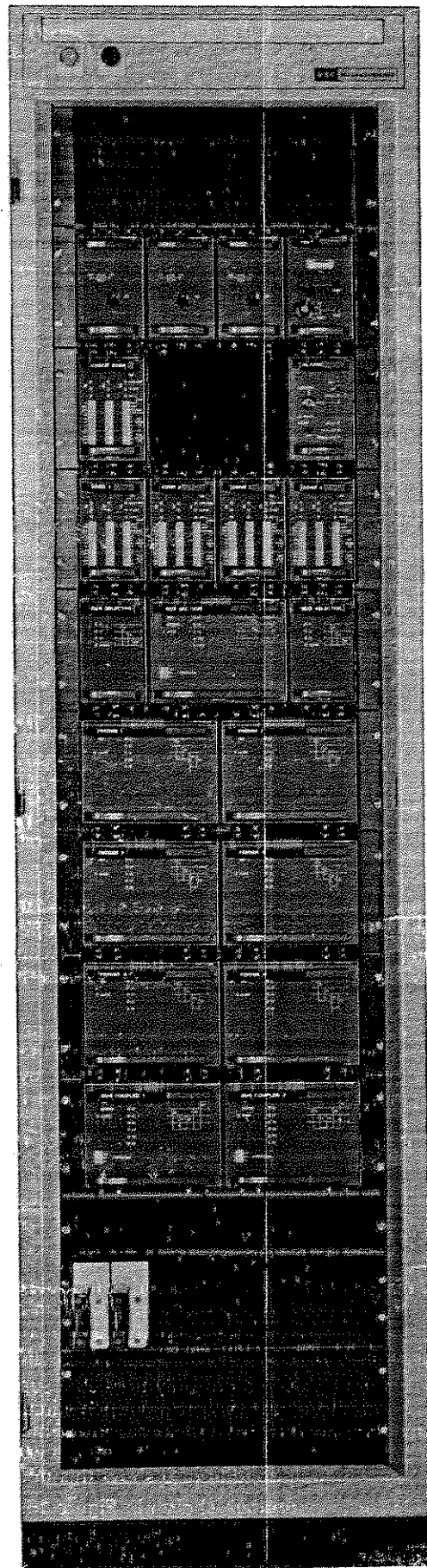


Figure 15.23 Static busbar protection, Type MBCZ.



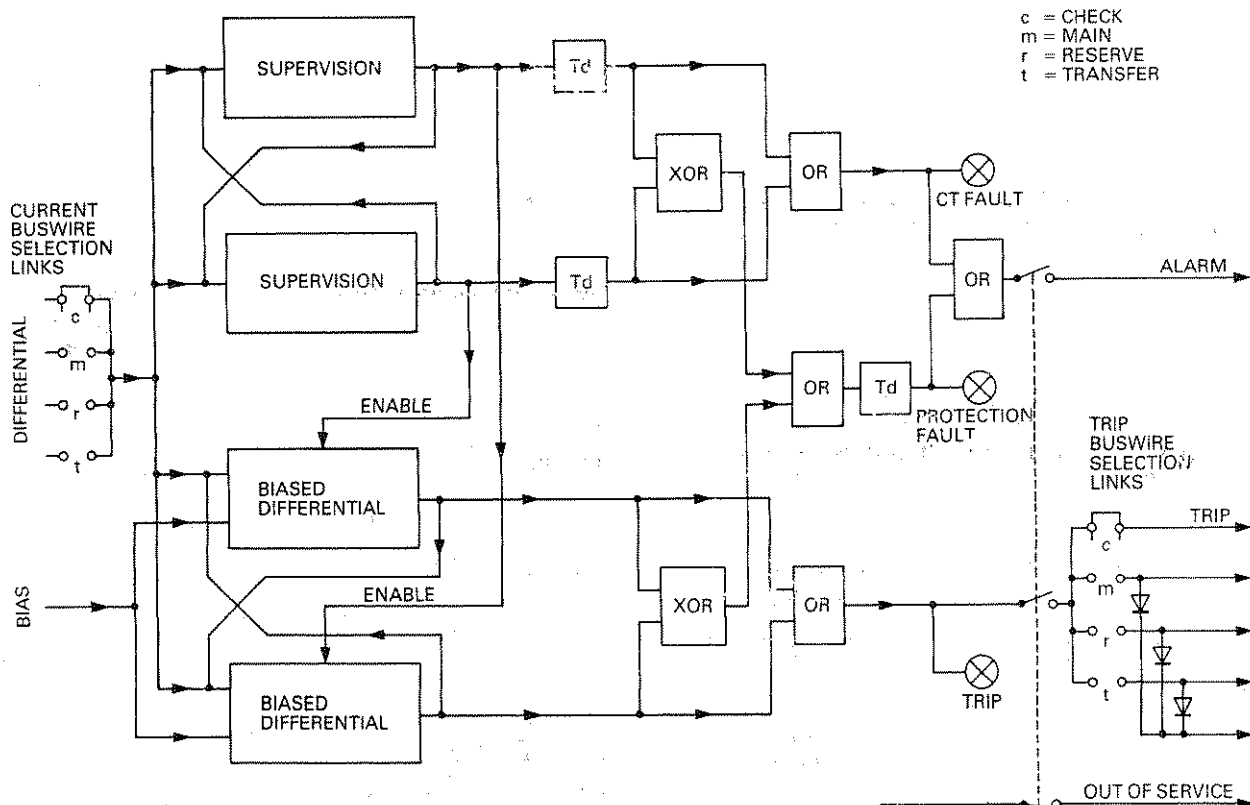


Figure 15.24 Block diagram of measuring unit.

### Operation for internal faults

If the CT's carrying fault current are not saturated there will be ample current in the differential circuit to operate the differential relay quickly for fault currents exceeding the minimum operating level, which is adjustable between  $0.2-2 \times$  rated current.

When the only CT(s) carrying internal fault current become saturated it might be supposed that the CT saturation detectors may completely inhibit operation by short-circuiting the differential circuit. However, the resulting inhibit pulses remove only an insignificant portion of the differential current, so operation of the relay is therefore virtually unaffected.

### 15.11.2 Discrepancy alarm feature

As shown in Figure 15.24 each measuring module contains duplicated biased differential elements and also a pair of supervision elements, which are a part of a comprehensive supervision facility.

This arrangement provides not only the usual supervision of CT secondary circuits, where an open circuit might cause maloperation, but also detects any impairment of the element to operate for an internal fault, without waiting for an actual system fault condition to show this up.

The criteria for operation are shown in Figure 15.25.

For a zone to operate it is necessary for both the differential supervision element and the biased differential element to operate. For a circuit breaker to be tripped it requires the associated main zone to be operated and also the overall check zone. Four separate elements must therefore operate before the trip can result.

### 15.11.3 Master/follower measuring units

When two sections of a busbar are connected together by isolators it will result in two measuring elements being connected in parallel when the isolators are closed to operate the two busbar sections as a single bar. The fault current will then divide between the two measuring elements in the ratio of their impedances. If both of the two measuring elements are of low and equal impedance the effective minimum operating current of the scheme will be doubled.

This is avoided by using a 'master/follower' arrangement. By making the impedance of one of the measuring elements very much higher than the other it is possible to ensure that one of the relays retains its original minimum operation current. Then to ensure that both the parallel connected zones are tripped the trip circuits of the two zones are connected in parallel.

Any measuring unit can have the role of 'master' or 'follower' as it is selectable by means of a switch on the front of the module.

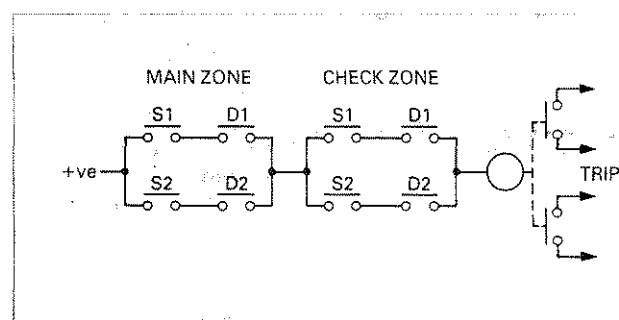


Figure 15.25 Busbar protection trip logic: double 2 out of 2.

#### 15.11.4

##### Ratio correction for main current transformers

Another important feature of the MBCZ scheme is that it has a ratio correction facility to enable mismatched main CT's to be used.

The auxiliary current transformer within each differential module has a range of tapings by which a mismatch of up to approximately 10:1 can be accommodated.

#### 15.11.5

##### Transfer tripping for breaker failure

Serious damage may result, and even danger to life, if a circuit breaker fails to open when called upon to do so. To reduce this risk breaker fail protection schemes were developed some years ago.

These schemes are generally based on the assumption that if current is still flowing through the circuit breaker a set time after it has been 'told' to trip, then it has failed to function. The circuit breakers in the next stage back in the system are then automatically tripped.

For a bus coupler or section breaker this would involve tripping all the infeeds to the adjacent zone, a facility which is included in the busbar protection scheme.

When the current transformers are mounted on one side only of the bus coupler, then this feature will also ensure that a fault between the CT and the circuit breaker is cleared. If current transformers are mounted on both sides of the circuit breaker this is not a problem since the protection zones can be overlapped.

#### 15.12

Ideally, the separate discriminating zones should overlap each other and also the individual circuit protections. The overlap should occur across a circuit breaker, so that the latter lies in both zones. For this arrangement it is necessary to install current transformers on both sides of the circuit breakers, which is possible with many but not all types of switchgear. With both the circuit and the bus protection current transformers on the same side of the circuit breakers, the zones may be overlapped at the current transformers, but a fault between the CT location and the circuit breaker will not be completely isolated. This matter is of significance in all switchgear to which the conditions apply, and is particularly important in the case of outdoor

switchgear of the air blast type where separately mounted, multi-secondary current transformers are generally used. The conditions are shown in Figure 15.26.

Figure 15.26(a) shows the ideal arrangement in which both the circuit and busbar zones are overlapped leaving no region unprotected.

Figure 15.26(b) shows how the mounting of all current transformers on the circuit side of the breaker leaves a small unprotected region. The fault shown will cause operation of the busbar protection, tripping the circuit breaker, but the fault will continue to be fed from the circuit, assuming that some source of power is connected. It is necessary for the bus protection to intertrip the far end of the circuit protection, if the latter is of the unit type. In the case of a feeder circuit the intertripping will usually be achieved by unstabilizing the feeder protection by, for example, short circuiting the protection pilots, or otherwise interfering with the balancing function, by means of a contact on the bus protection tripping relay.

The alternative arrangement, in which all the current transformers are mounted on the busbar side of the circuit breaker, is shown in Figure 15.26(c). The conditions here are reversed, and it is necessary for the bus protection to be intertripped from the feeder protection. Since it is clearly unsatisfactory for the busbar section to be cleared for all feeder faults, this operation only takes place if the fault continues to be fed after the breaker has opened.

A special overcurrent relay, type PDI, is used for this purpose. The relay consists of a single element of the induction pattern with a summation type energizing winding. The unit is fitted with wound type shading windings on subsidiary poles which must be closed for the relay to operate. The relay is designed to have a saturating characteristic giving a substantially constant operating time of 0.4 seconds for current inputs above four times setting.

The relay is interlocked with the circuit protection by a contact on the latter which closes the shading winding circuit. Only if the circuit protection has tripped and the fault current continues to flow for a further 0.4 seconds is an intertrip passed to the bus protection to effect the necessary clearance by tripping all circuit breakers connected to the faulty busbar.

In the former case, Figure 15.26(b), a similar technique may be used, particularly when the circuit includes a generator. In this case the intertrip proves that the fault is in the switchgear connections and not in the generator; the latter is therefore tripped electrically but not shut down on the mechanical side so as to be immediately ready for further service if the fault can be cleared.

#### 15.13

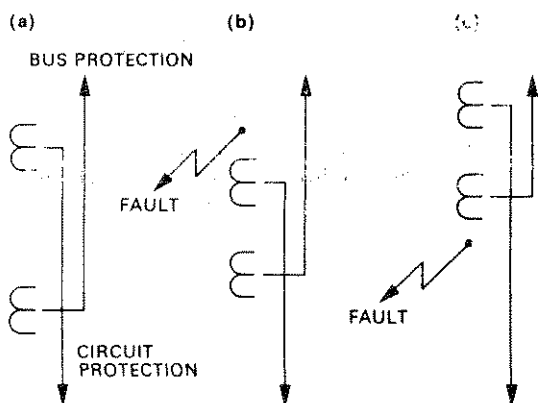
##### TRIPPING CIRCUITS

The d.c. tripping circuits, although ancillary to the fundamental measuring relays, are vital to the schemes and should obviously be of the highest order of reliability. The wiring should be segregated from that for other functions to avoid any possibility of 'sneak' circuits.

The most common procedure for high impedance differential schemes is to use two separate tripping relays for each section switch and one tripping relay per feeder breaker, the latter being connected to the tripping bus wires via auxiliary switches in double bus equipments. This is the simplest and most reliable arrangement, and one which permits easy extension; see Figure 15.15.

In low impedance schemes it is usual to allocate a separate trip element of the protection to each circuit breaker.

In order to avoid spurious operation by, for example, the discharge of the d.c. wiring capacitance, it is desirable to have contacts on both sides of the tripping relays; it is satisfactory to have the discriminative zone contacts on the positive side and the check system contacts on the

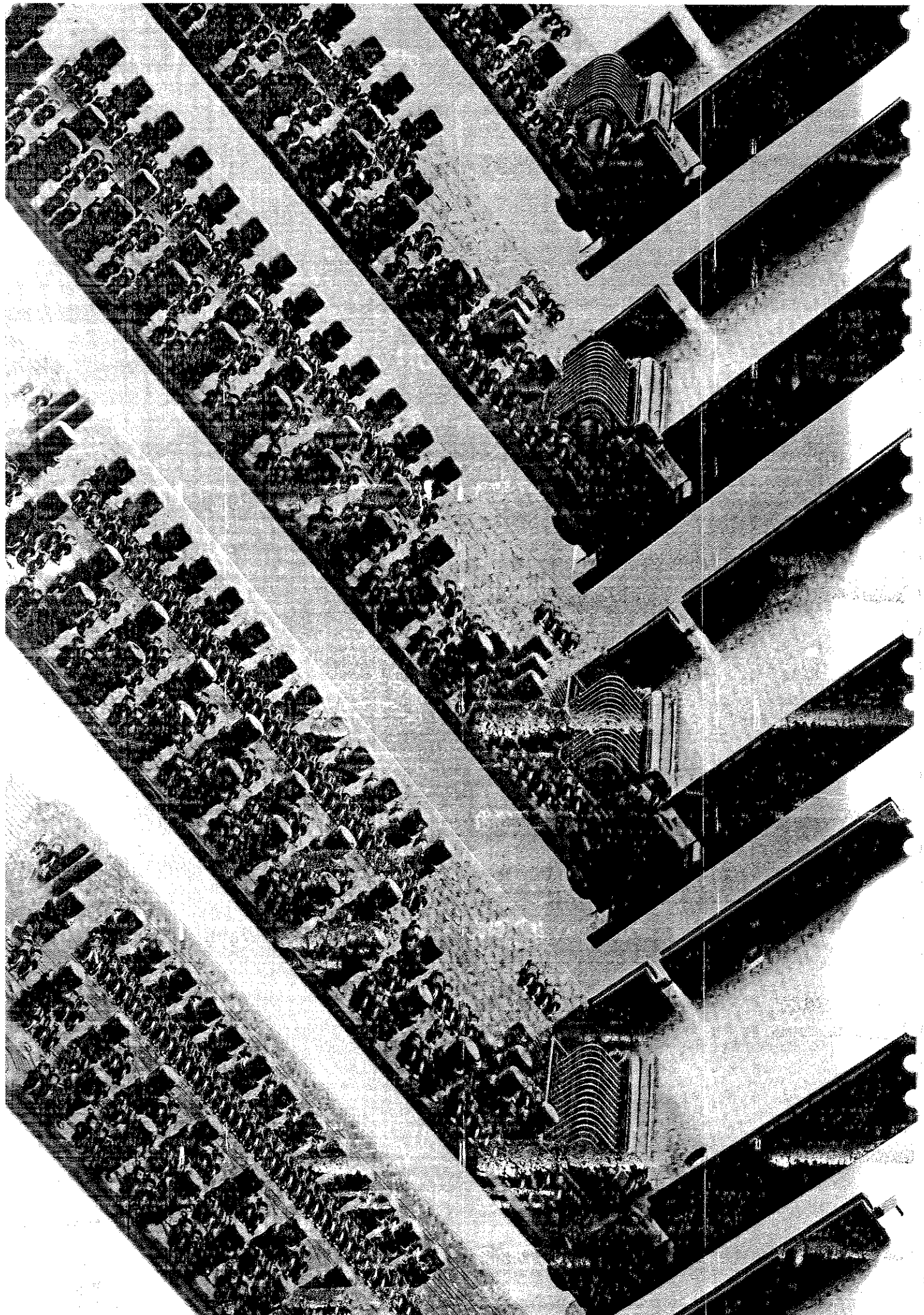


- Current transformers mounted on both sides of breaker  
—no unprotected region.
- Current transformers mounted on circuit side only of breaker  
—fault shown not cleared by busbar protection
- Current transformers mounted on busbar side only of breaker  
—fault shown not cleared by circuit protection.

Figure 15.26 Unprotected zone with current transformers mounted on one side of the circuit breaker only.

negative side. Since such an isolated relay might assume almost any potential, to avoid any risk of electrolytic corrosion taking place it is good practice to ensure that the coil is connected to the negative pole by connecting a resistor across the check relay contacts. This resistor should be chosen so as to pass no more than a quarter of the minimum operating current of the tripping relay.

Links are usually provided to isolate the tripping circuit of any zone for testing purposes.



# Transformer and transformer-feeder protection

- 16.1 Introduction.
- 16.2 Magnitude and effects of transformer faults.
- 16.3 Lightning inrush.
- 16.4 Loading protection.
- 16.5 Overcurrent protection.
- 16.6 Grounded earth fault protection.
- 16.7 Potential protection.
- 16.8 Transformer protection.
- 16.9 Combined differential and restricted earth fault schemes.
- 16.10 Winding transformer protection.
- 16.11 Refusing protection.
- 16.12 High-earth protection.
- 16.13 Oil and gas devices.
- 16.14 Transformer-feeder protection.
- 16.15 Reripping.

## 16.1

The power transformer is one of the most important links in a power transmission and distribution system; it also possesses a wide range of characteristics and certain special features which make complete protection difficult. These conditions must be reviewed before the detailed application of protection is considered.

The choice of suitable protection is also governed by economic considerations. Although this factor is not unique to power transformers, it is brought into prominence by the wide range of transformer ratings used in transmission and distribution systems which can vary from a few kVA up to several hundred MVA. Only the simplest protection, such as fuses, can be justified for transformers of the lower ratings, whereas those of the highest ratings should have the best protection that can be designed.

## 16.2

A fault on a transformer winding is controlled in magnitude not only by the source and neutral earthing impedance but also by the leakage reactance of the transformer and the fact that the fault voltage may differ from the system voltage according to the position of the fault in the winding. Several distinct cases arise; these are examined below.

### 16.2.1

#### Star-connected winding with neutral point earthed through an impedance

An earth fault on such a winding will give rise to a current which is dependent on the value of the earthing impedance, and is also proportional to the distance of the fault from the neutral point, since the fault voltage will be directly proportional to this distance.

The ratio of transformation between the primary winding and the short-circuited turns also varies with the position of the fault, so that the current which flows into the transformer primary terminals will be in proportion to the square of the fraction of the winding which is short-circuited. The effect is shown in Figure 16.1, from which it may be noticed that faults in the lower third of the winding produce very little current through the line connections.

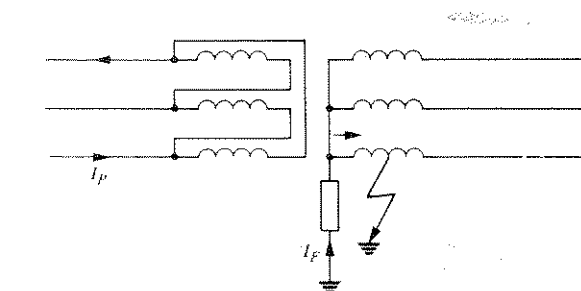
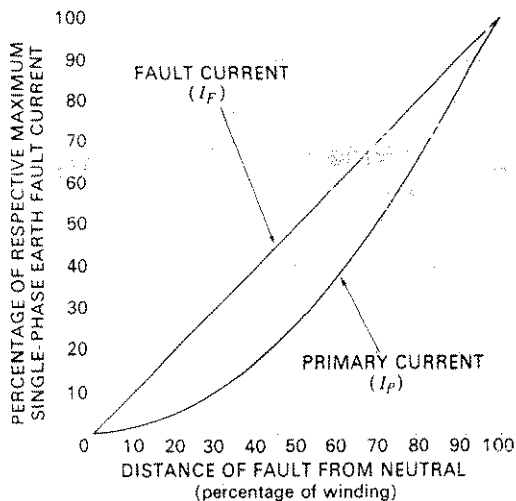


Figure 16.1 Earth fault current in resistance-earthed star winding.

### 16.2.2

#### Star-connected winding with neutral point solidly earthed

The fault current in this case is controlled mainly by the leakage reactance of the winding, which varies in a complex manner with the position of the fault. The variable fault point voltage is also an important factor, as in the case of impedance earthing, but the reactance decreases so rapidly for points approaching the neutral that the fault current is actually highest for a fault near the neutral end of the winding. The variation of current with fault position is shown in Figure 16.2.

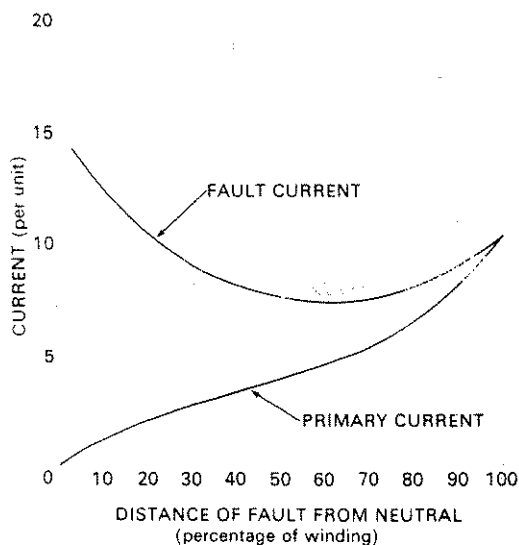


Figure 16.2 Earth fault current in solidly earthed star winding.

The fault current is modified as before by the variable transformation ratio to give the input current; as the fault current magnitude stays high throughout the winding and, further, the general scale of current is high in the absence of external limiting impedance, the input current curve remains at a substantial level for faults at most points along the winding.

### 16.2.3

#### Delta-connected winding

No part of a delta-connected winding operates with a voltage to earth of less than 50% of the phase voltage. The range of fault current magnitude for such a winding is therefore less than for a star winding. The actual value of fault current will still depend on the way the system is earthed; it should also be remembered that the impedance of a delta winding is particularly high to fault currents flowing to a centrally placed fault on one leg. The impedance can be expected to be between 25% and 50%, based on the transformer rating, regardless of the normal balanced through-current impedance. As the prefault voltage to earth at this point is half the normal phase voltage, the earth fault current may be no more than the rated current, or even less than this value if the source or system earthing impedance is appreciable. The current will flow to the fault from each side through the two half windings, and will be divided between two phases of the system. The individual phase currents may therefore be relatively low, a fact which must be remembered when considering the performance of a protection scheme.

### 16.2.4

#### Phase to phase faults

Faults between phases within a transformer are relatively rare; if such a fault does occur it will give rise to a substantial current comparable to the earth fault currents discussed in Section 16.2.2.

### 16.2.5

#### Interturn faults

In low voltage transformers, interturn insulation breakdown is unlikely to occur unless the mechanical force on the winding due to external short circuits has caused chafing or cracking of the insulation, or moisture has been admitted to the oil.

A high voltage transformer connected to an overhead transmission system is very likely to be subjected to steep fronted impulse voltages. A line surge, which may be of several times the rated system voltage, will concentrate on the end turns of the winding because of the high

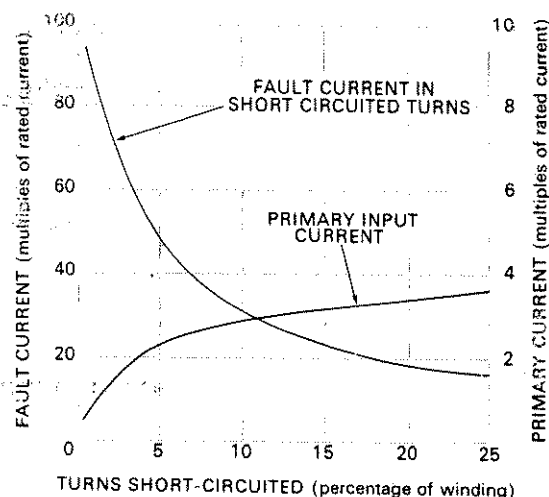


Figure 16.3 Interturn fault current/number of turns short circuited.



equivalent frequency of the surge front. The interturn insulation of the end turns is reinforced, but cannot be increased in proportion to the insulation to earth, which is relatively great. The risk of a partial winding flash-over compared with that of a breakdown to earth is therefore comparatively high. It is claimed that 70%—80% of all transformer failures arise from faults between turns. The subsequent progress of the fault, if not detected in the earliest stage, may well destroy the evidence of the true cause.

A short circuit of a few turns of the winding will give rise to heavy fault current in the short-circuited loop, but the terminal currents will be very small, because of the high ratio of transformation between the whole winding and the short-circuited turns.

The graph in Figure 16.3 shows the corresponding data for a typical transformer of 3.25% normal through impedance with the short-circuited turns symmetrically located in the centre of the winding.

### 16.2.6

#### Core faults

A conducting bridge across the laminated structure of the core can permit sufficient eddy-current to flow to cause serious overheating. The bolts which clamp the core together are always insulated, to avoid this trouble. If any portion of the core insulation becomes defective, the resultant heating may reach a magnitude sufficient to damage the winding.

The additional core loss, although causing severe local heating, will not produce a noticeable change in input current and could not be detected by the normal electrical protection; it is nevertheless highly desirable that the condition should be detected before a major fault has been created. Fortunately, in an oil-immersed transformer, if the heating of any part of the core structure is sufficient to be liable to cause damage to the winding insulation, it will also cause breakdown of some of the oil with an accompanying evolution of gas. This gas will escape to the conservator, and is used to operate a mechanical relay; see Section 16.13.3.

### 16.2.7

#### Tank faults

Loss of oil through tank leaks will ultimately produce a dangerous condition, either because of a reduction in winding insulation or because of overheating on load due to the loss of effective cooling.

Oil sludging can block cooling ducts and pipes, leading to overheating on load. A similar effect is produced by the failure of the forced cooling systems applied to large transformers.

### 16.2.8

#### Externally applied conditions

Sources of abnormal stress in a transformer are:

- Overload.
- System faults.
- Overvoltage.
- Reduced system frequency.

Overload causes increased 'copper loss' and a consequent temperature rise. Overloads can be carried for limited periods, depending on the initial temperature and the cooling conditions (see BS Code of Practice CP1010: Guide to Loading of Transformers).

The thermal time constant of ONAN (oil natural, air natural) transformers is of the order of 2.5—5 hours. Shorter time constants will apply to force-cooled transformers.

System short circuits produce a relatively intense rate of heating of the feeding transformers, the copper loss in-

creasing in proportion to the square of the per unit fault current. The duration of external short circuits that a transformer can sustain without damage if the current is limited only by self reactance is typically shown in Table 16.1.

| Transformer reactance (%) | Fault current (multiple of rating) | Permitted fault duration (seconds) |
|---------------------------|------------------------------------|------------------------------------|
| 4                         | 25                                 | 2                                  |
| 5                         | 20                                 | 3                                  |
| 6                         | 16.6                               | 4                                  |
| 7                         | 14.2                               | 5                                  |

Table 16.1 Fault withstand levels

Large fault currents produce severe mechanical stresses in transformers; the maximum stress occurs during the first cycle of asymmetric fault current and so cannot be averted by automatic tripping of the circuit. The control of such stresses is therefore a matter of transformer design.

Overvoltage conditions are of two kinds:

- Transient surge voltages.
- Power frequency voltage.

Transient overvoltages arise from switching and lightning disturbances and are liable to cause interturn faults, as described in Section 16.2.5. These overvoltages are usually limited by shunting the high voltage terminals to earth either with a plain rod gap, the so-called co-ordinating gap, or by surge diverters, which comprise a stack of short gaps in series with a non-linear resistor. The surge diverter has the advantage of extinguishing the flow of power current after discharging a surge, in this way avoiding a system fault that would require the transformer to be isolated, which is what happens with the simple protective gap.

Power frequency overvoltage causes both an increase in stress on the insulation and a proportionate increase in the working flux. The latter effect causes an increase in the iron loss and a disproportionately great increase in magnetizing current. In addition, flux is diverted from the laminated core structure into steel structural parts. In particular, under conditions of over-excitation of the core, the core bolts, which normally carry little flux, may be subjected to a large component of flux diverted from the highly saturated and constricted region of core alongside.

Under such conditions, the bolts may be rapidly heated to a temperature which destroys their own insulation and will damage the coil insulation if the condition continues.

Reduction of frequency has an effect with regard to flux density, similar to that of overvoltage.

It follows that a transformer can operate with some degree of overvoltage with a corresponding increase in frequency, but operation must not be continued with a high voltage input at a low frequency.

Operation cannot be sustained when the ratio of voltage to frequency, with these quantities given values per unit of their rated values, exceeds unity by more than a small amount, for instance if  $V/f > 1.1$ . The base of 'unit voltage' should be taken as the highest voltage for which the transformer is designed if a substantial rise in system voltage has been catered for in the design.

## 16.3

The phenomenon of magnetizing inrush is a transient condition which occurs primarily when a transformer is energized. It is not a fault condition, and therefore does not necessitate the operation of protection, which, on the contrary, must remain stable during the inrush transient, a requirement which is a major factor in the design of protective systems for transformers.

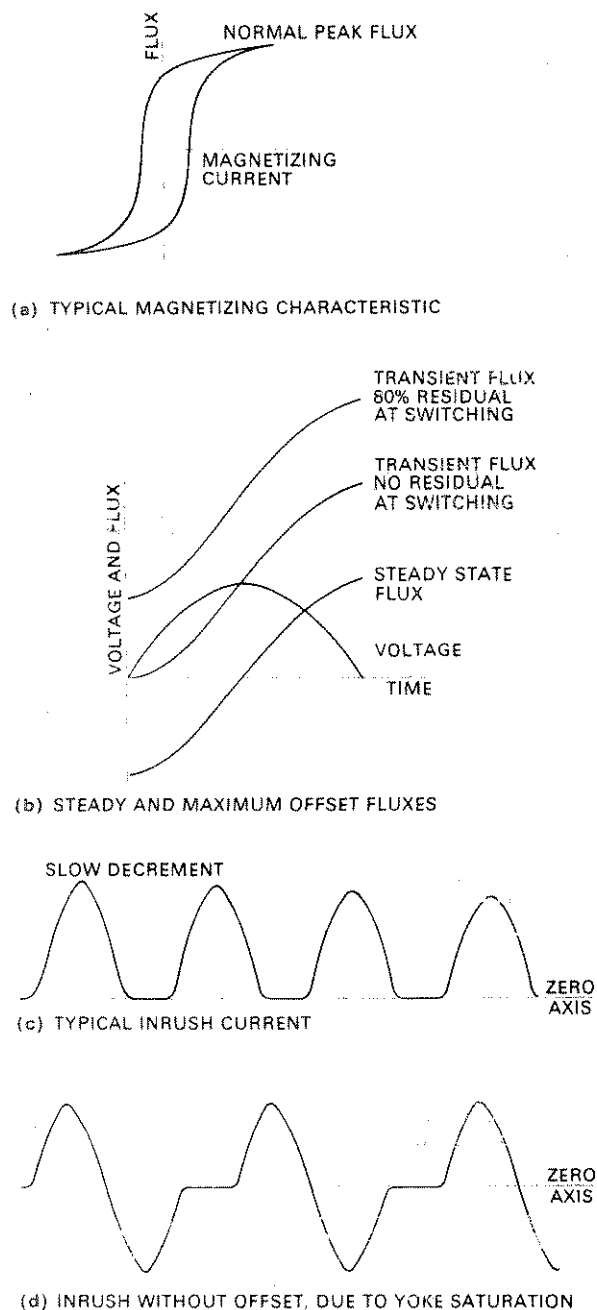


Figure 16.4 Transformer magnetizing inrush.

When an inductor is energized by a steady alternating voltage, the flux linking the inductive circuit varies from a peak negative value to an equivalent peak positive value during one half cycle of the voltage wave. The flux change of twice the maximum flux value is proportional to the time integral of the voltage wave between successive zero points. On switching on at the zero point of the wave, the full flux change is required during the first half cycle, but with the flux initially zero, the maximum flux developed will be nearly twice the normal peak value as shown in Figure 16.4(b).

If the inductor is linear, as, for example, is an air-cored inductor, the current taken will also rise to nearly twice the steady state value. A transformer primary winding, however, can be treated as an iron-cored inductor in which the normal peak flux is close to saturation value. An increase of flux to double this value corresponds to extreme saturation. The magnetizing current therefore rises to a very high value which may exceed the rated full load value—hence the term 'current inrush'.

Residual flux can increase the current still further. If the initial remanent flux, instead of being zero, has an initial positive value, that is, an initial value in the same direction as the flux change, the increment of flux must remain the same, since it is proportional to the half cycle voltage loop, and the peak value attained will be of the order of 2.8 times the normal value with 80% remanence.

The very high flux densities quoted above are so far beyond the normal working range that the incremental relative permeability of the core approximates to unity and the inductance of the winding falls to a value near that of the 'air-cored' inductance. The current wave, starting from zero, increases slowly at first, the flux having a value just above the residual value and the permeability of the core being moderately high. As the flux passes the normal working value and enters the highly saturated portion of the magnetizing characteristic, the inductance falls and the current rises rapidly to a peak which may be five hundred times the steady state magnetizing current. When the peak is passed at the next voltage zero, the following negative half cycle of the voltage wave reduces the flux to the starting value, the current falling symmetrically to zero; see Figure 16.4(c). The current wave is therefore fully offset and, as with the offset wave in a linear inductor, is only restored to the steady state condition by the circuit losses. The time constant of the transient is relatively long, being from perhaps 0.1 seconds for a 100 kVA transformer and up to 1.0 seconds for a large unit. As the magnetizing characteristic is non-linear, the envelope of the transient current is not strictly of exponential form; the magnetizing current can be observed to be still changing up to 30 minutes after switching on.

Switching at other instants of the voltage wave produces lower values of transient current. If the point on the wave is chosen so that the residual flux is the correct value for that instant under steady conditions, no transient will occur and the steady no-load current will be taken immediately.

In the case of three-phase transformers, the point-on-wave at switch-on differs for each phase and different inrush currents are drawn in consequence. Some inter-phase mutual interference also takes place, because of the combination of the phase fluxes in the yokes. In this way it is possible for a phase with a point-on-wave of energization which in itself would produce no inrush transient to receive nevertheless an inrush current of substantial magnitude. In this case the current waveform will not be offset from the zero axis but will be distorted, generally as shown in Figure 16.4(d).

### 16.3.1

#### Harmonic content of inrush waveform

The waveform of transformer magnetizing current contains a proportion of harmonics which increases as the peak flux density is raised to the saturating condition. As long as the waveform is symmetrical about the horizontal axis, only odd harmonics will be present. The condition is typical for normal alternating currents flowing through impedances which have no directional polarizing property. The magnetizing current of a transformer is of this class and will contain a third harmonic and progressively smaller amounts of fifth and higher harmonics. If the degree of saturation is progressively increased, not only will the harmonic content increase as a whole but the relative proportion of fifth harmonic will increase and eventually overtake and exceed the third harmonic. At a still higher level the seventh would overtake the fifth harmonic but this involves a degree of saturation that will not be experienced with power transformers.

The energizing conditions which result in an offset inrush current produce a waveform which is not symmetrical about the horizontal axis but which is symmetrical, neglecting decrement, about certain ordinates. Such a wave



typically contains both even and odd harmonics. Typical inrush currents contain substantial amounts of second and third harmonics and diminishing amounts of higher orders. As with the steady state wave, the proportion of harmonics varies with the degree of saturation, so that as a severe inrush transient decays, the harmonic makeup of the current passes through a range of conditions. Even the inrush current shown in Figure 16.4(d), which has no offset, is not symmetrical about the horizontal axis but possesses mirror-image symmetry about chosen ordinates. This waveform, therefore, possesses even, as well as odd, harmonics.

#### 16.4

### TEMPERATURE PROTECTION

The rating of a transformer is based on the temperature rise above an assumed maximum ambient temperature; under this condition no sustained overload is usually permissible. At a lower ambient temperature some degree of overload can be safely applied. Short period overloads are also permissible to an extent dependent on the previous loading conditions. No precise ruling applicable to all conditions can be given concerning the magnitude and duration of safe overload.

The only certain statement is that the winding must not overheat; a temperature of about  $95^{\circ}\text{C}$  is considered to be the normal maximum working value beyond which a further rise of  $8^{\circ}\text{--}10^{\circ}\text{C}$ , if sustained, will halve the life of the unit.

Protection against overload is therefore based on winding temperature, which is usually measured by a thermal image technique.

The thermal sensing element is placed in a small pocket

located near the top of the transformer tank in the hot oil. A small heater, fed from a current transformer in the lower voltage terminal of one phase, is also located in this pocket and produces a local temperature rise, similar to that of the main windings, above the general oil temperature.

The sensing element therefore experiences a temperature similar to that of the winding under all conditions, correctly taking into account the effects of ambient temperature and previous loading history.

Dial thermometers comprising a pressure-type instrument connected by capillary tubing to a bulb in the oil pocket and filled with a suitable liquid have been extensively used in the past.

A well-proven system is provided in the type TTT relay. Here the sensing element is a heat sensitive silicon resistor, or Silistor, which is incorporated, with the heating element, in a thermal mass of moulded material, the whole forming a thermal replica of the transformer winding. The replica, which is in the form of a short cylinder, is placed in the pocket in the transformer tank about ten inches below the tank top, which is estimated to be the hottest layer in the oil. The scheme is indicated in Figure 16.5.

The Silistor forms one arm of a resistance bridge which is energized from a stabilized d.c. source. The unbalance output signal energizes an indicating instrument and the voltage across the Silistor is applied to static sensing circuits, which control forced cooling pumps and fans, give warnings of overheating and ultimately trip the transformer circuit breakers.

The control circuits are arranged to reset with a definite but adjustable differential. The alarm and trip outputs do not require this feature.

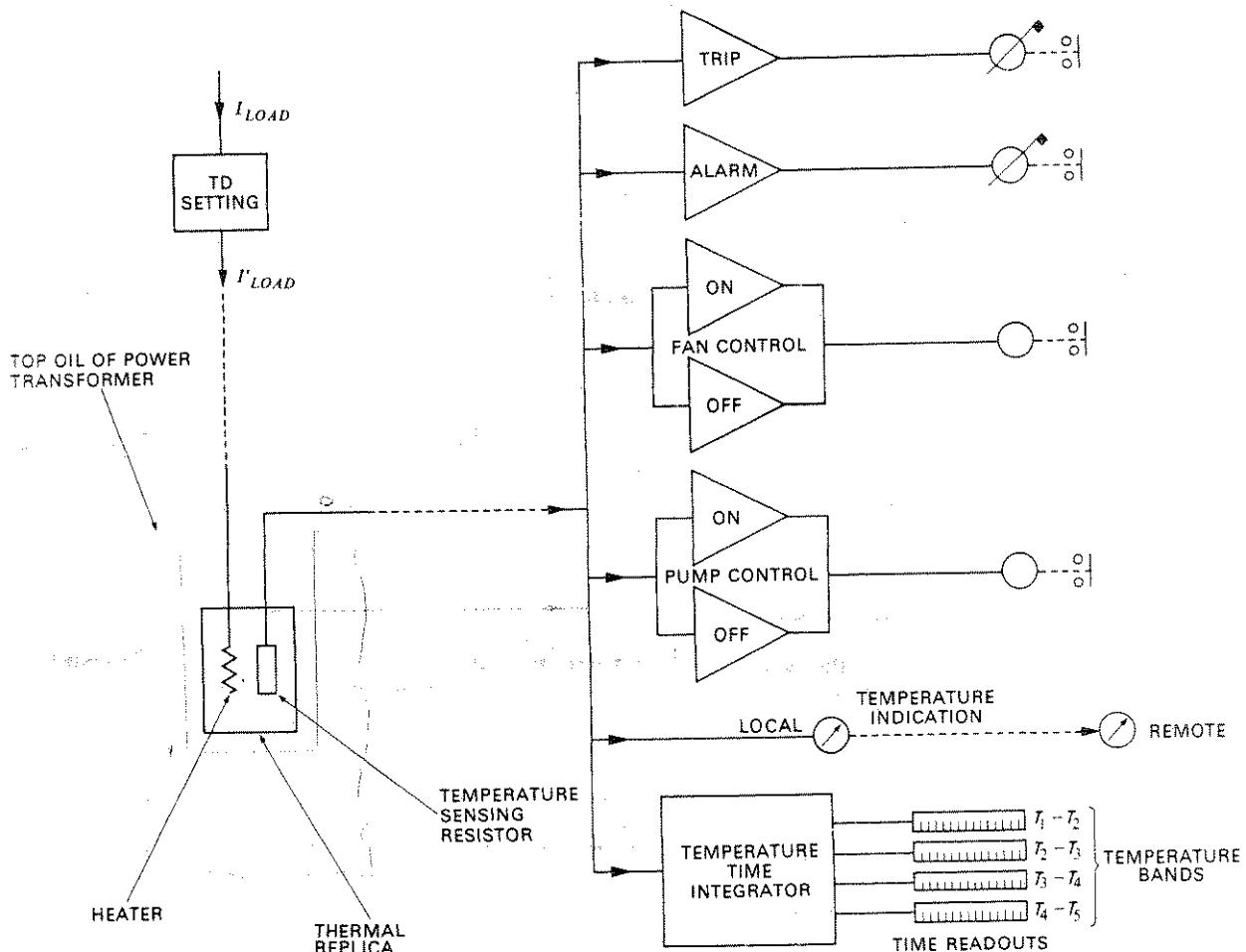


Figure 16.5 Schematic diagram for transformer winding temperature relay.

The simulated winding temperature can be displayed on a d.c. instrument calibrated in degrees Centigrade mounted locally or remote, or indication at both locations can be given.

#### 16.4.1

##### Temperature-time integrator

A further refinement in the supervision of a transformer is obtained by integrating the periods during which the transformer has been overheated to a given degree, thereby building up the life history of the unit as far as heating and consequent deterioration of the insulation is concerned.

In the type CTTT temperature-time integrator, electrolytic coulometers are used. The meter element is a glass capillary tube filled with mercury. The indicating gap is the electrolyte. When a small current, about  $1\mu\text{A}$ , is passed through the coulometer, mercury is transferred from the anode to the cathode, thereby moving the end of the mercury column across the scale in 10,000 hours.

Four coulometers are used. The signal from the resistance bridge in the type TTT overheating protection relay is applied via separate level detector circuits and reed output relays to the coulometers, the detectors being adjusted to switch at successive selected temperatures and a positive interlock being used to ensure that only one coulometer is energized at any one time. Thus each indicator measures only in the band between its own setting and the next higher one. The temperature bands usually chosen are:

|                 |                             |
|-----------------|-----------------------------|
| 100—110°C       | 10,000 hours for full scale |
| 110—120°C       | 10,000 hours for full scale |
| 120—130°C       | 1000 hours for full scale   |
| 130°C and above | 1000 hours for full scale   |

The instrument will therefore indicate for how long the winding temperature has been in each temperature band, which is sufficient to enable a reasonable estimate of the degree of ageing of the transformer to be made.

#### 16.5

##### Overcurrent protection

#### 16.5.1

##### Fuses

Small distribution transformers are commonly protected only by fuses. In many cases no circuit breaker is provided, making fuse protection the only available means of automatic isolation. Fuses are overcurrent devices, and must have ratings well above the maximum transformer load current in order to carry, without 'blowing', the short duration overloads that may occur because of such as motor starting; also, the fuses must withstand the magnetizing inrush currents drawn when power transformers are energized. Moreover, High Rupturing Capacity (HRC) fuses, although very fast in operation with large fault currents, are extremely slow with currents of less than three times their rated value. It follows that such fuses will do little to protect the transformer, serving only to protect the system by disconnecting a faulty transformer after the fault has reached an advanced stage.

The above remarks will be made clear in Table 16.2, which shows typical ratings of fuses for use with 11 kV transformers.

| Transformer rating |                       | Fuse              |                                         |
|--------------------|-----------------------|-------------------|-----------------------------------------|
| kVA                | Full load current (A) | Rated current (A) | Operating time at $3 \times$ rating (s) |
| 100                | 5.25                  | 16                | 3.0                                     |
| 200                | 10.5                  | 25                | 3.0                                     |
| 300                | 15.8                  | 36                | 10.0                                    |
| 500                | 26.2                  | 50                | 20.0                                    |
| 1000               | 52.5                  | 90                | 30.0                                    |

Table 16.2 Typical fuse ratings

This table should be taken only as a typical example; considerable differences exist in the time characteristics of different types of HRC fuses. Furthermore grading with protection on the secondary side has not been considered.

#### 16.5.2

##### Overcurrent relays

The larger transformers, 100 kVA and over, may be controlled by circuit breakers, in which case protection can be provided by overcurrent trips or by relays. Improvement in protection is obtained in two ways; the excessive delay of the HRC fuse for the lower fault currents are avoided and an earth fault tripping element is provided in addition to the overcurrent feature.

The time delay characteristic should be chosen to discriminate with circuit protection on the secondary side.

Instantaneous trips may be added, the current setting being chosen to avoid operation with a short circuit on the secondary side. Alternatively, HRC fuses may be used to back up the circuit breaker. Although full discrimination with the secondary circuit protection is necessary, the fuse rating need not be as high as the through fault current; the time characteristic of the fuse can be taken into account and discrimination is likely to be obtained with fuses rated at between 2 and 6 times the transformer full load current, depending on the transformer reactance, the source fault power and whether the secondary system is a single circuit or subdivided into several branches each with individual protection.

The main function of such instantaneous protection is to give high speed clearance of terminal short circuits; the settings, therefore, may be made relatively high.

The primary winding of a distribution transformer will usually be earthed, making reverse flow of earth fault current impossible. Equally, no zero sequence current can be transmitted to the secondary system. The setting of earth fault protection may therefore be low, with regard to both current and time, the limitation being entirely on account of the performance of the current transformer. An excessively low relay current setting may give a poor effect, a setting, as discussed in Section 9.16.

In order to maintain good discrimination the earth fault element should remain stable under phase fault conditions, which is more likely to be achieved with a low relay setting because of the high impedance of the relay on a low tap setting. In general, a setting of 20% is a good compromise between the conflicting requirements of sensitivity and stability.

If phase fault stability is achieved, the time setting can be reduced to the minimum value, since time grading of earth fault elements is not involved.

#### 16.6

##### RESTRICTED EARTH FAULT PROTECTION

A simple overcurrent and earth fault system will not give good protection cover for a star-connected primary winding, particularly if the neutral is earthed through an impedance, as considered in Section 16.2.1. The degree of protection is very much improved by the application of a unit differential earth fault system or restricted earth fault protection, as shown in Figure 16.6. The residual current of three line current transformers is balanced against the output of a current transformer in the neutral conductor. The relay is of the high impedance type, the theory of which is set out in Section 10.4.1.

The system is operative for faults within the region between current transformers, that is, for faults on the star winding in question. The system will remain stable for faults outside this zone.

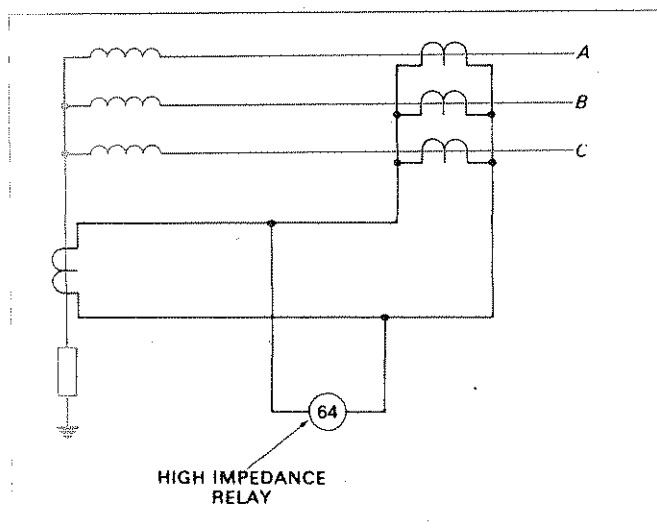


Figure 16.6 Restricted earth fault protection for a star winding.

The gain in protection performance comes not only from using an instantaneous relay with a low setting, but also because the whole fault current is measured, not merely the transformed component in the HV primary winding. Hence, although the prospective current level decreases as fault positions progressively nearer the neutral end of the winding are considered, the square law which controls the primary line current is not applicable, and with a low effective setting, a good percentage of the winding can be covered.

Restricted earth fault protection is often applied even when the neutral is solidly earthed. Since fault current then remains at a high value even to the last turn of the winding (Figure 16.2), virtually complete cover for earth faults is

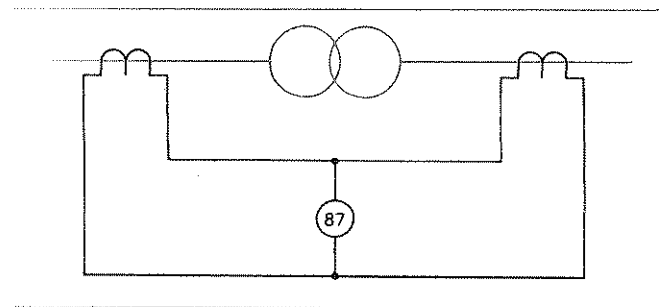


Figure 16.7 Principle of transformer differential protection.

obtained, which is a gain compared with the performance of systems which do not measure the neutral conductor current.

Earth fault protection applied to a delta-connected or unearthed star winding is inherently restricted, since no zero sequence component can be transmitted through the transformer to the secondary system. A high impedance relay can therefore be used, giving fast operation and phase fault stability.

Both windings of a transformer can be protected separately with restricted earth fault protection, thereby providing high speed protection against earth faults for the whole transformer with relatively simple equipment.

## 16.7

### DIFFERENTIAL PROTECTION

The restricted earth fault schemes described above in Section 16.6 depend entirely on the Kirchoff principle that the sum of the currents flowing into a conducting network is zero. A differential system can be arranged to cover the complete transformer; this is possible because of the high efficiency of transformer operation, and the close equivalence of ampere-turns developed on the primary and secondary windings. Figure 16.7 illustrates the principle. Current transformers on the primary and secondary sides are connected to form a circulating current system.

#### 16.7.1

##### Basic considerations for transformer differential protection.

###### a. Line current transformer primary ratings

The rated currents of the primary and secondary sides of a two winding transformer will depend on the MVA rating of the transformer and will be in inverse ratio to the corresponding voltages. For three winding transformers the rated current will depend on the MVA rating of the relevant winding. Line current transformers should therefore have primary ratings equal to or above the rated currents of the transformer windings to which they are applied. Primary ratings will often be limited to those of available standard ratio CTs. For example, current transformers of 1600/1 A and 200/1 A have been chosen for the protection of the two winding 11 kV/132 kV, 30 MVA transformer considered in Section 16.7.1(d).

###### b. Current transformer connections

The CT connections should be arranged, where necessary, to compensate for phase differences between line currents on each side of the power transformer. If the transformer is

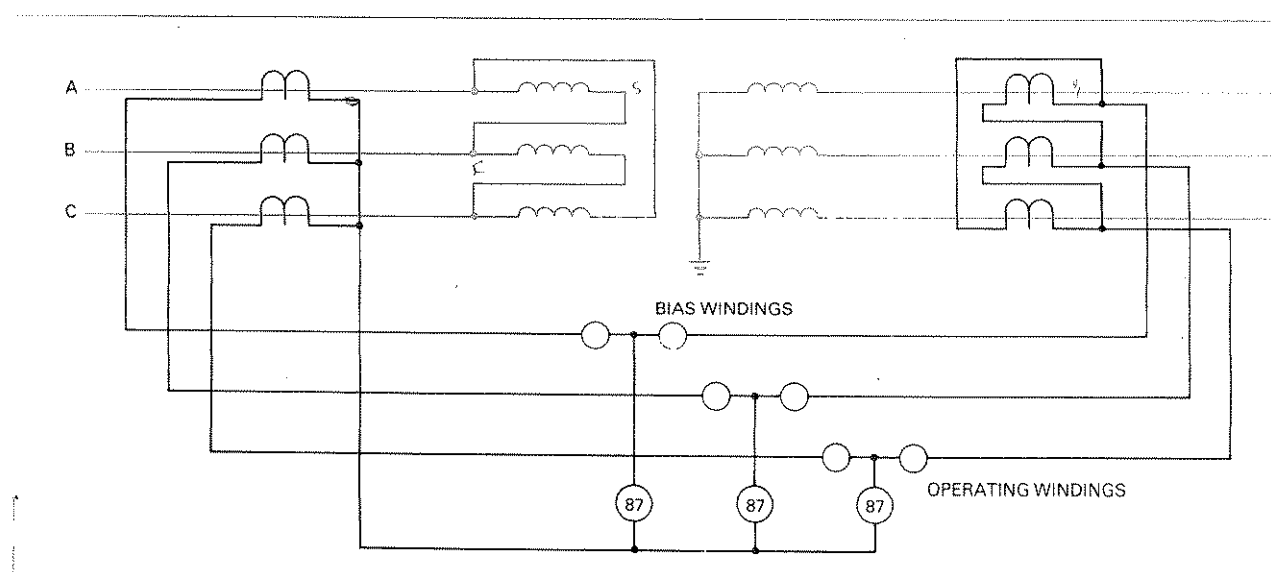
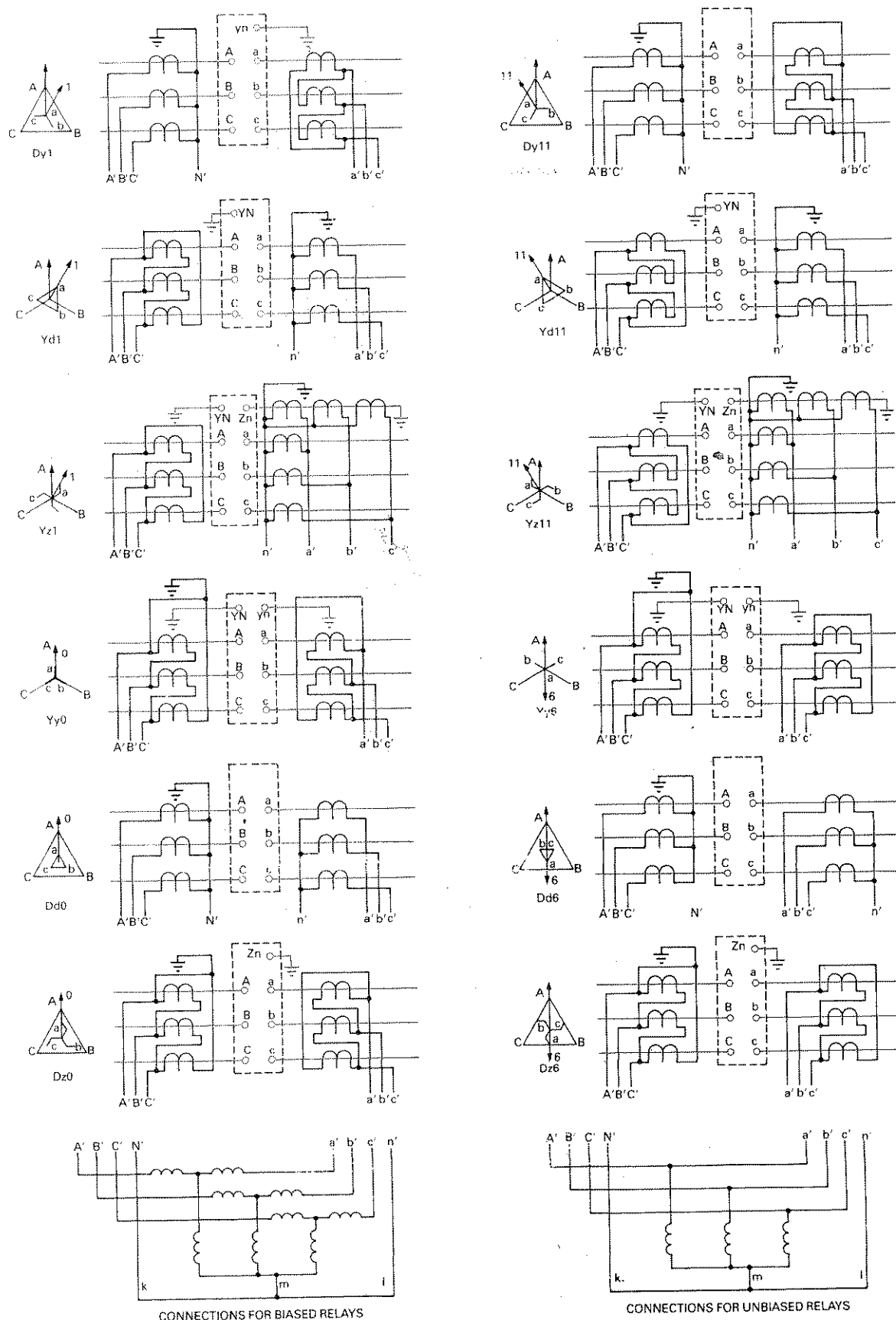


Figure 16.8 Biased differential protection for two-winding delta/star transformer.



#### NOTES ON RELAY CONNECTIONS

1. Connection 'k' or 'l' is omitted when corresponding CT's are delta-connected. When both sets of CT's are delta-connected 'k', 'l' and 'm' are omitted.
2. It is essential that CT connections are earthed, at one point only.
3. When the power transformer to be protected has 3 windings, it may be helpful to consider firstly the relative connections for the CT's associated with windings 1 and 2, and then those with windings 1 and 3. As a final check the relation between the CT's on windings 2 and 3 may be considered.
4. The power transformer vector group references correspond to those specified in IEC 76: 1967 and BS 171: 1970.

Figure 16.9 Current transformer connections for power transformers of various vector groups.

connected delta/star, as shown in Figure 16.8, balanced three-phase through current suffers a phase change of  $30^\circ$ , which must be corrected in the CT secondary leads by appropriate connection of the CT secondary windings.

Furthermore, zero sequence current flowing on the star side of the power transformer will not produce current outside the delta on the other side. The zero sequence must therefore be eliminated from the star side by connecting the current transformers in delta, from which it follows that the current transformers on the delta side of the transformer must be connected in star, in order to give the  $30^\circ$  phase shift. This is a general rule; if the transformer were connected star/star, the current transformers on both sides would need to be connected in delta.

When current transformers are connected in delta, their secondary ratings must be reduced to  $1/\sqrt{3}$  times the secondary rating of star-connected current transformers, in order that the currents outside the delta may balance with the secondary currents of the star-connected current transformers.

When line CT ratios provide adequate matching between currents supplied to the differential relay under through-load and through-fault conditions, the necessary phase shift can be obtained by suitable connection of the line CTs. Figure 16.9 shows the required connections for various power transformer winding arrangements.

When delta connected CTs are required it is a common alternative practice to use star connected line CTs and to obtain the delta connection by means of star/delta interposing CTs, as exemplified in Section 16.7.1(d).

### c. Bias to cover tap-changing facility and CT mismatch

If the transformer has a tapping range enabling its ratio to be varied, this must be allowed for in the differential system. This is because if the current transformers are chosen to balance for the mean ratio of the power transformer, a variation in ratio from the mean will create an unbalance proportional to the ratio change. At maximum through-fault current, the spill output produced by the small percentage unbalance may be substantial.

Differential protection should be provided with a proportional bias of an amount which exceeds in effect the maximum ratio deviation. This stabilizes the protection under through fault conditions while still permitting the system to have good basic sensitivity.

The bias characteristic for a typical differential protection is shown in Figure 16.10 from which it can be seen that the

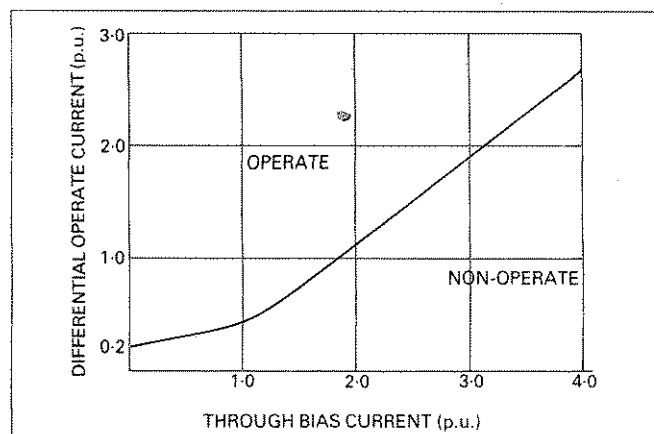


Figure 16.10 Typical bias characteristic.

current required to operate the relay increases as the through-fault current increases.

When applying a differential relay, care should be taken that its characteristic will prevent operation due to the combination of tap change variation and CT mismatch. To

minimize the effect of tap change variations, current inputs to the differential relay are usually matched at the mid point of the tap range.

Figure 16.8 shows percentage bias differential protection for a two-winding transformer. The two bias windings per phase are commonly provided on the same electromagnet or auxiliary transformer core.

The Merz-Price principle remains valid for a system having more than two connections, so a transformer with three or more windings can still be protected by the application of the above principles.

When the power transformer has only one of its three windings connected to a source of supply, with the other two windings feeding loads at different voltages, a relay of the same design as that used for a two-winding transformer can be employed, connected as shown in Figure 16.11(a). The separate load currents are summated in the CT secondary circuits, and will balance with the infeed current on the supply side.

When more than one winding is connected to a source, the distribution of current cannot readily be predicted and there is a danger in the scheme in Figure 16.11(a) of current circulating between the two paralleled sets of current transformers without producing any bias. It is therefore important that bias be obtained separately from the current flowing in each set of line connections. In this case a relay is used with separate bias windings, arranged so that their mechanical or electrical effects always add numerically, that is not vectorially, to give the total bias effect. This is shown in Figure 16.11(b).

These considerations do not apply when the third winding consists of a delta-connected tertiary with no connections brought out. Such an arrangement may be regarded as a two winding transformer for protection purposes and may be protected as shown in Figure 16.11(c).

### d. Interposing CTs to compensate for mismatch of line CTs

Besides their use for phase compensation, interposing CTs may be used to match up currents supplied to the differential protection from the line CTs for each winding. As previously described, the amount of CT mismatch which a relay can tolerate without maloperation under through-current conditions will depend on its bias characteristic and the range over which the tap changer can operate. If the combined mismatch due to CTs and tap changer is above the acceptable level, then interposing CTs may be used to achieve current matching at the mid point of the tap changer range.

For the protection of two winding transformers, interposing CTs should ideally match the relay currents under through load conditions corresponding to the maximum MVA rating of the transformer.

An example of this for an 11 kV/132 kV, 30 MVA, delta/star transformer is shown in Figure 16.12.

First, the primary ratings of 1600 A and 200 A chosen for the main current transformers should not be less than the maximum full load currents in each winding, which are:

$$\frac{30 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 1575 \text{ A} \quad \text{for the 11 kV winding,}$$

and

$$\frac{30 \times 10^6}{\sqrt{3} \times 0.8 \times 132 \times 10^3} = 164 \text{ A} \quad \text{for the 132 kV winding.}$$

For the 11 kV winding this is also the nominal full load current, but for the 132 kV winding, with  $-5\%$  tap, the latter is:

$$\frac{30 \times 10^6}{\sqrt{3} \times 0.95 \times 132 \times 10^3} = 138 \text{ A}$$

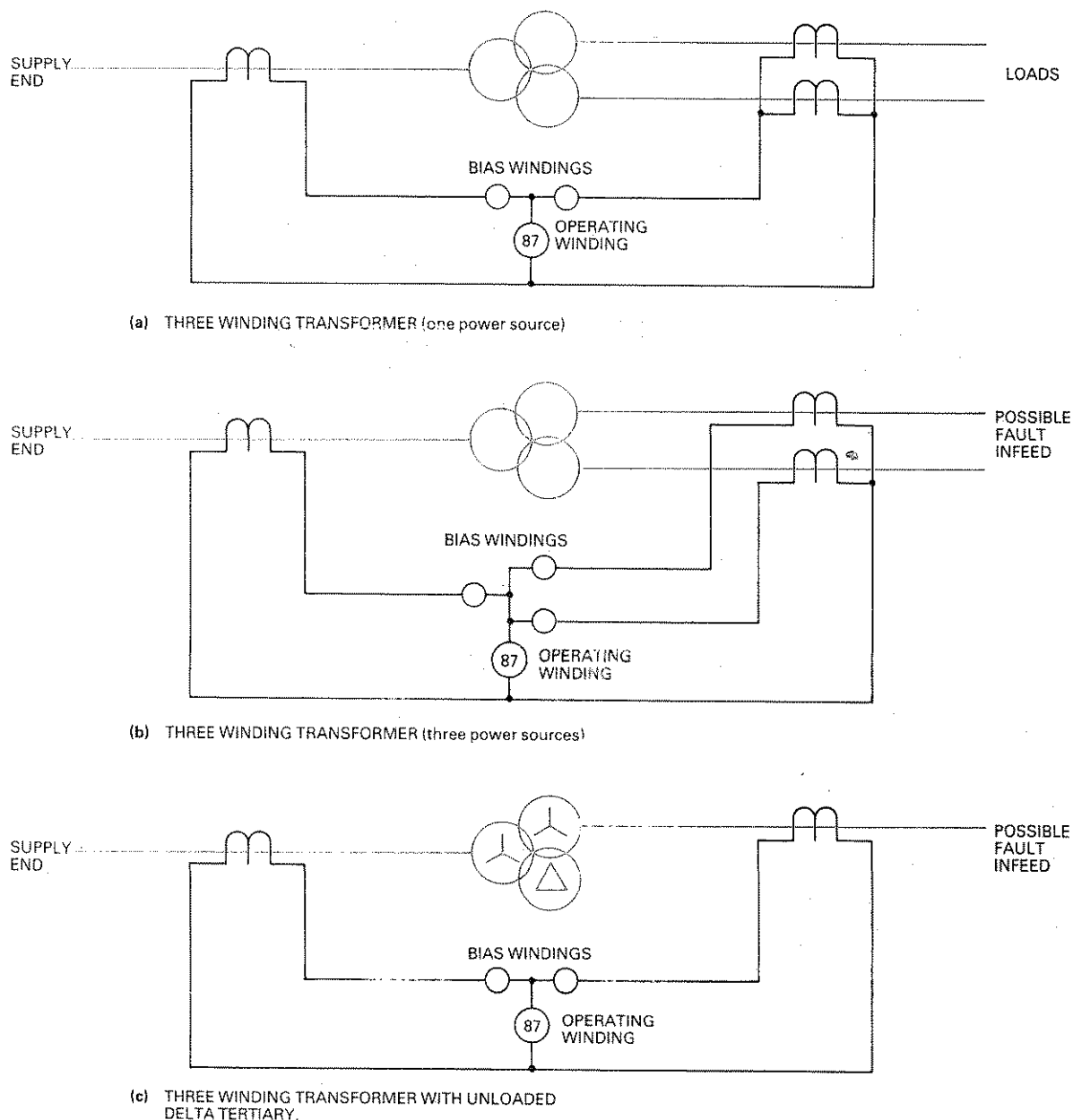


Figure 16.11 Biased differential protection arrangements, shown as single phase diagrams for simplicity.

Equivalent secondary currents in the line CTs are 0.984 A and 0.69 A. Thus the ratio of the star/delta interposing CTs to achieve ideal matching is given by:

$$0.69 \left/ \frac{0.984}{\sqrt{3}} \right. = 0.70 \left/ \frac{1}{\sqrt{3}} \right. \text{A or } 0.70/0.577 \text{ A.}$$

The protection of three winding transformers is complicated by the fact that line CTs for each winding are normally based on different MVA levels and will not themselves achieve balance under through current conditions. To achieve correct balance it is necessary to use interposing CTs which will provide the relay with rated current when the rating of the highest rated winding is applied to all windings.

An example for a 500 kV/138 kV/13.45 kV, 120 MVA/90 VA/30 MVA, star/star/delta transformer is shown in Figure 16.13.

$$\text{Load current at 500 kV} = \frac{120 \times 10^6}{\sqrt{3} \times 500 \times 10^3} = 138.6 \text{ A}$$

$$\text{Load current at 138 kV} = \frac{90 \times 10^6}{\sqrt{3} \times 138 \times 10^3} = 376.5 \text{ A}$$

$$\text{Load current at 13.45 kV} = \frac{30 \times 10^6}{\sqrt{3} \times 13.45 \times 10^3} = 1288 \text{ A}$$

$$\text{Line CT ratio at 500 kV} = 200/5 \text{ A}$$

$$\text{Line CT ratio at 138 kV} = 400/5 \text{ A}$$

$$\text{Line CT ratio at 13.45 kV} = 1500/5 \text{ A}$$

$$\text{Current at 138 kV corresponding to 120 MVA}$$

$$= \frac{120 \times 10^6}{\sqrt{3} \times 138 \times 10^3} = 502 \text{ A}$$

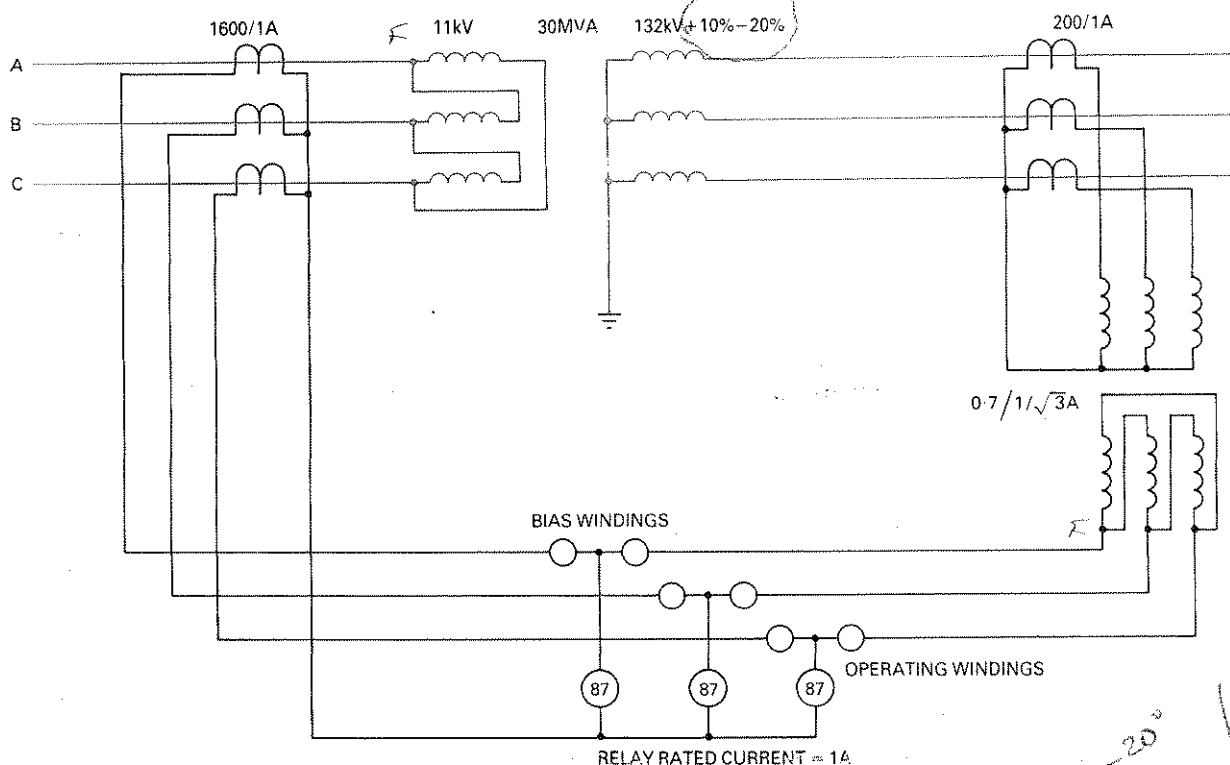


Figure 16.12 Example of differential protection applied to a two winding transformer showing use of interposing current transformers.

Current at 13.45 kV corresponding to 120 MVA

$$= \frac{120 \times 10^6}{\sqrt{3} \times 13.45 \times 10^3} = 5151 \text{ A}$$

Secondary current from 500 kV line CTs corresponding to 120 MVA

$$= \frac{138.6 \times 5}{200} = 3.46 \text{ A}$$

therefore ratio of required star/delta interposing CTs

$$= 3.46 / \frac{5}{\sqrt{3}} \text{ A or } 3.46/2.89 \text{ A}$$

Secondary current from 138 kV line CTs corresponding to 120 MVA

$$= \frac{502 \times 5}{400} = 6.28 \text{ A}$$

therefore ratio of required star/delta interposing CTs

$$= 6.28 / \frac{5}{\sqrt{3}} \text{ A or } 6.28/2.89 \text{ A}$$

Secondary current from 13.45 kV line CTs corresponding to 120 MVA

$$\frac{5151 \times 5}{1500} = 17.17 \text{ A}$$

therefore ratio of required star/star interposing CTs

$$= 17.17/5 \text{ A}$$

Under full load conditions of 30 MVA for the 13.45 kV delta winding, the current appearing in the primary of the 17.17/5 A interposing CT will be only 4.29 A, the corresponding secondary current being 1.25 A. However the ratings of the primary and secondary windings should ideally be 17.17 A and 5 A respectively to minimise winding resistances.

### 16.7.2

#### Stabilization of differential protection during magnetizing inrush conditions

The magnetizing inrush phenomenon described in Section 16.3 produces current input to the energized winding which has no equivalent on the other sides of the transformer. The whole of the inrush current appears, therefore, as unbalance and superficially is not distinguishable from internal fault current. The normal bias is not, therefore, effective and increase of the protection setting to a value which would avoid operation would make the protection of little value.

#### Time delay

Since the phenomenon is transient, stability can be maintained by providing a small time delay. This has been achieved by various means.

An instantaneous relay can be shunted by a fuse link, a so-called kick-fuse, thereby diverting most of the current. The fuse is chosen so as to carry the inrush transient without blowing; only in the event of an internal fault does the fuse blow and permit the relay to operate.

Induction pattern relays of the I.D.M.T. type can also be used to give a suitable time delay.

The type DDT induction pattern relay has both a suitable

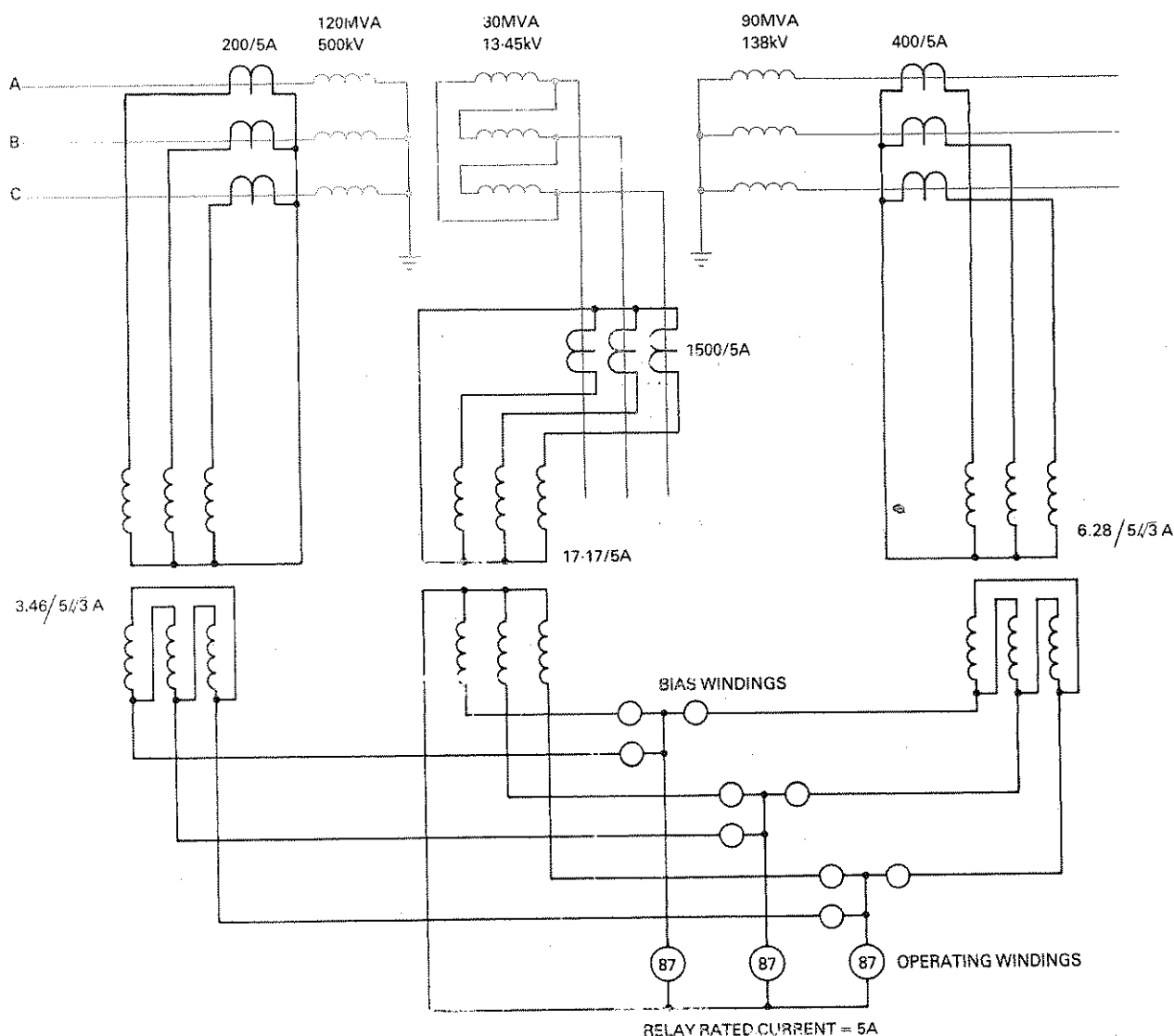


Figure 16.13 Example of differential protection applied to a three winding transformer showing use of interposing current transformers.

time characteristic and also a through-bias feature. Two induction electromagnets operate on a single disc, to produce opposed torques. The elements are connected into a Merz-Price system as shown in Figure 16.8, the setting being adjustable from 40—100%; the bias slope can be selected by taps to be either 20%, 30% or 40%.

A small time delay in operation is produced by an appropriate movement of the disc in combination with the braking action on the disc of a permanent magnet. The operating time at five times the setting current is adjustable between 100 and 250 milliseconds. A mid-adjustment to about 120 milliseconds will usually be found to be satisfactory.

The above time delay might be thought insufficient to give stability with a severe inrush current. In practice it is generally sufficient arising from the relatively poor response of the induction element to uni-directional current.

### Harmonic restraint

If damage to important transformers is to be minimized it is essential to clear faults without delay, and another solution to the inrush phenomenon must be found.

The inrush current, although generally resembling an in-zone fault current, differs greatly when the waveforms are

compared. The distinctive difference in the waveforms can be used to distinguish between the conditions.

As stated before, the inrush current contains all orders of harmonic, but these are not all equally suitable for providing bias. The study of this subject is complex, as the waveform depends on the degree of saturation and on the grade of iron in the core. The principal conclusions can be summarized as follows.

#### a. D.c or offset component (zero harmonic)

A uni-directional component will usually be present in the inrush current of a single-phase transformer and in the principal inrush currents of a three-phase unit. However, if at the instant of switching the residual flux for any phase is equal to the flux which would exist in the steady state at that point on the voltage wave, then no transient disturbance should take place on that phase.

Large inrush currents will flow in the other two phases, corresponding to high peak flux values established in these phase cores. The high flux circulates through the yokes, the saturation of which affects the first phase, which would have had no inrush effect, causing a substantial transient current to flow in this phase as well. This latter current, however, will not be offset from the zero axis, although the current waveform will be distorted; see Figure 16.4(d).



If the uni-directional current component were used to stabilize a differential system, some sort of cross-phase biasing would be required because of this effect.

Since many fault current waveforms will have initial offset, delay in tripping would result from the use of this component.

#### b. Second harmonic

This component is present in all inrush waveforms. It is typical of waveforms in which successive half period portions do not repeat with reversal of polarity but in which mirror-image symmetry can be found about certain ordinates.

The proportion of second harmonic varies somewhat with the degree of saturation of the core, but is always present as long as the uni-directional component of flux exists. It has been shown to have a minimum value of about 20% of the amount by which the inrush current exceeds the steady state magnetizing current.

The waveform discussed in (a) above and shown in Figure 16.4(d) contains a typical proportion of second harmonic component, since, although not offset, it arises from a uni-directional flux.

Normal fault currents do not contain second or other even harmonics, nor do distorted currents flowing in saturated iron cored coils under steady state conditions.

The output current of a current transformer which is energized into steady state saturation will also contain odd harmonics but not even harmonics. However, should the current transformer be saturated by the transient component of the fault current, the resulting saturation is not symmetrical and even harmonics are introduced into the output current. This can have the advantage of improving the through fault stability performance of a differential relay, but it also has the adverse effect of increasing the operation time for internal faults.

The second harmonic is therefore an attractive basis for a stabilizing bias against inrush effects, but care must be taken to ensure that the current transformers are sufficiently large so that the harmonics produced by transient saturation do not delay normal operation of the relay.

The differential current is passed through a filter which extracts the second harmonic; this component is then applied to produce a restraining quantity sufficient to overcome the operating tendency due to the whole of the inrush current which flows in the operating circuit.

By this means a sensitive and high speed system can be obtained. With the type DTH relay, a static design, a setting of 15% is obtained, with an operating time of 45 milliseconds for all fault currents of twice or more times the current rating.

The relay will restrain when the second harmonic component exceeds 20% of the current.

#### c. Third harmonic

The third harmonic is also present in the inrush current in roughly comparable proportion to the second harmonic. The separate phase inrush currents are still related in phase to the primary applied electromotive forces and the harmonics have a similar time spacing, which brings the third harmonic waves in the three windings into phase. If the windings are connected in delta, the line currents are each

the difference of two phase currents. As the inrush components vary during the progress of the transient condition it is possible for this difference to pass through zero, so that the third harmonic component in the line current vanishes; this component cannot, therefore, be regarded as a reliable source of bias.

To this must be added the further consideration that a sustained third harmonic component is quite likely to be produced by CT saturation under heavy in-zone fault conditions.

All this means that the third harmonic is not a desirable means of stabilizing a protective system against inrush effects.

#### d. Higher harmonics

All other harmonics are theoretically present in inrush current but the relative magnitude diminishes rapidly as the order of harmonic increases; there may be 5% of fourth harmonic in a given inrush current. This component would be similar in response to the second harmonic but the small magnitude hardly justifies the provision of an extra filter circuit.

A still smaller proportion of fifth harmonic will be present. This component is not subject to cancellation as is the third harmonic, and can be present in the output of a CT in an advanced state of saturation, therefore offering no benefit. Still higher harmonics are of magnitude too small to be worth consideration.

The percentage of fifth harmonic in the transformer magnetizing current increases significantly when the transformer is subjected to a temporary overvoltage condition. Some manufacturers apply a measure of fifth harmonic bias to the relay to restrain operation for this condition. Typically such relays are restrained if the magnetizing current contains 30% fifth harmonic.

The effects of the excessive flux density produced by the application of an overvoltage is described in Section 16.2.8.

### Modern alternative to harmonic bias

#### a. Inrush detection

Another feature that characterizes an inrush current can be seen from Figure 16.4 where the two waveforms (c) and (d) have periods in the cycle where the current is zero. The minimum duration of this zero period is theoretically one quarter of the cycle and is easily detected by a simple timer

T1 that is set to  $\frac{1}{4f}$  seconds. Figure 16.14 shows the circuit

in block diagram form. Timer T1 produces an output only if the current is zero for a time exceeding  $\frac{1}{4f}$  seconds. It is

reset when the instantaneous value of the differential current exceeds the setting reference.

As the zero in the inrush current occurs towards the end of the cycle it is necessary to delay operation of the differential relay by  $\frac{1}{f}$  seconds to ensure that the zero condition can

be detected if present. This is achieved by using a second timer T2 which is held reset by an output from timer T1.

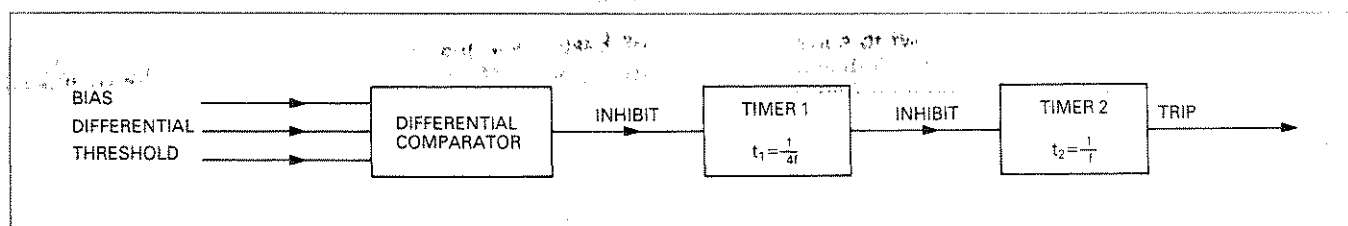


Figure 16.14 Block diagram to show waveform gap-detecting principle.

When no current is flowing for a time exceeding  $\frac{1}{4f}$  seconds, timer T2 is held reset and the differential relay which may be controlled by these timers is not permitted to trip. When a differential current exceeding the setting of the relay flows, timer T1 is reset and timer T2 times out to give a trip signal in  $\frac{1}{f}$  seconds. If the differential current is characteristic of transformer inrush then timer T2 will be reset on each cycle and the trip signal is blocked.

#### b. Transformer overfluxing detection.

When a transformer is subjected to an overvoltage it takes large pulses of current for the portion of each cycle during which the instantaneous value of the voltage exceeds the 'knee' of the magnetizing curve for the transformer core. The magnetizing current will therefore have two periods in each cycle where the current is below the differential setting threshold of the relay as shown in Figure 16.15. Typically each of these periods exceeds  $\frac{1}{4f}$  seconds duration.

Operation of the relay will therefore be blocked for this form of magnetizing current.

As the degree of overfluxing increases, the zero gaps become shorter. However a rise in voltage of more than 40% would be required to reach the point where the gap technique would no longer suffice. A similar performance would be obtained using fifth harmonic restraint against overfluxing. However a voltage rise of this order would be unusual, resulting in an unacceptable degree of overfluxing requiring the application of an overfluxing relay such as the type GTT.

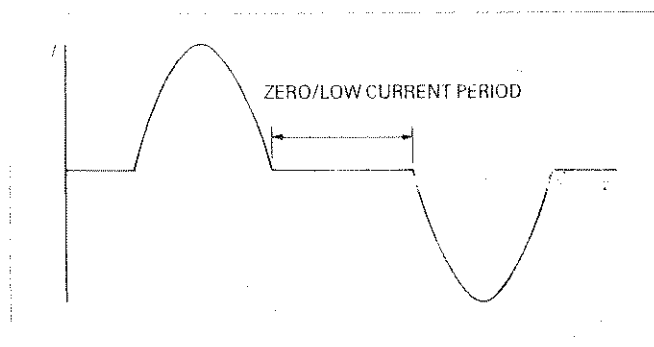


Figure 16.15 Magnetizing current during overfluxing condition.

The type MBCH relay uses the current zero detection technique to give consistent operation times for internal faults without resorting to large current transformers.

#### 16.7.3

##### Rough balance scheme

A variation of the simple differential protection provides both differential protection and general system back-up and overload protection using only a triple pole I.D.M.T. relay.

A normal circulating current system is set up, but the ratios of the current transformers are chosen so as to depart from the true balance condition by a small amount. The relay is a standard I.D.M.T. type having a setting above the differential current during full load conditions.

In the example illustrated in Figure 16.16(a), the transformer is rated at 7.5 MVA, 33 kV/11 kV connected delta-star. Full load currents are 131 A and 593 A respectively. Current transformers are 150/5 A star-connected on the 33 kV side and 1000/5 A or 577/2.83 A delta-connected on the 11 kV side. Full load three-phase current will produce outputs from the CT groups as follows:

$$33 \text{ kV side: } \frac{131}{150} \times 5 = 4.37 \text{ A}$$

$$11 \text{ kV side: } \frac{393}{1000} \times 5 \times \sqrt{3} = 3.4 \text{ A}$$

A current of 0.97 A will therefore flow in the relay.

If the relay has a setting of 25% of 5 A, the system will have an effective overcurrent setting of:

$$\frac{1.25}{0.97} \times 100\%$$

that is, 129% of the rated current of the transformer. Thus both differential protection with a nominal setting of 25% and a general overload feature are obtained with the same relay.

If the need to use current transformers of standard ratios causes difficulty in obtaining a desired overcurrent setting, interposing current transformers can be introduced, as shown in Figure 16.16(b).

#### 16.8

##### AUTO-TRANSFORMER PROTECTION

Auto-transformers are sometimes used to couple EHV power networks if the ratio of their voltages is moderate. Differential protection as described above can be applied, but, as an alternative, protection can be based on the application of Kirchhoff's law to a conducting network, namely that the sum of the currents flowing into all external connections to the network is zero.

A circulating current system is arranged between equal ratio current transformers in the two groups of line connections and the neutral end connections. If one neutral current transformer is used, this and all the line current transformers can be connected in parallel to a single element relay, thus providing a scheme responsive to earth faults only—see Figure 16.17(a).

If current transformers are fitted in each phase at the neutral end of the windings and a three element relay is used, a differential system can be provided, giving full protection against phase and earth faults; see Figure 16.17(b).

The relays are of the high impedance instantaneous unbiased type, similar to the single element relays used for restricted earth fault protection.

This protection can be of good sensitivity and the highest speed. It is unaffected by ratio changes on the transformer due to tap-changing and is immune to the effects of magnetizing inrush current.

On the debit side, it does not respond to interturn faults, a deficiency which is serious in view of the high statistical risk quoted in Section 16.2.5. Such faults, unless otherwise cleared, will be left to develop into earth faults, by which time considerably more damage to the transformer will have occurred.

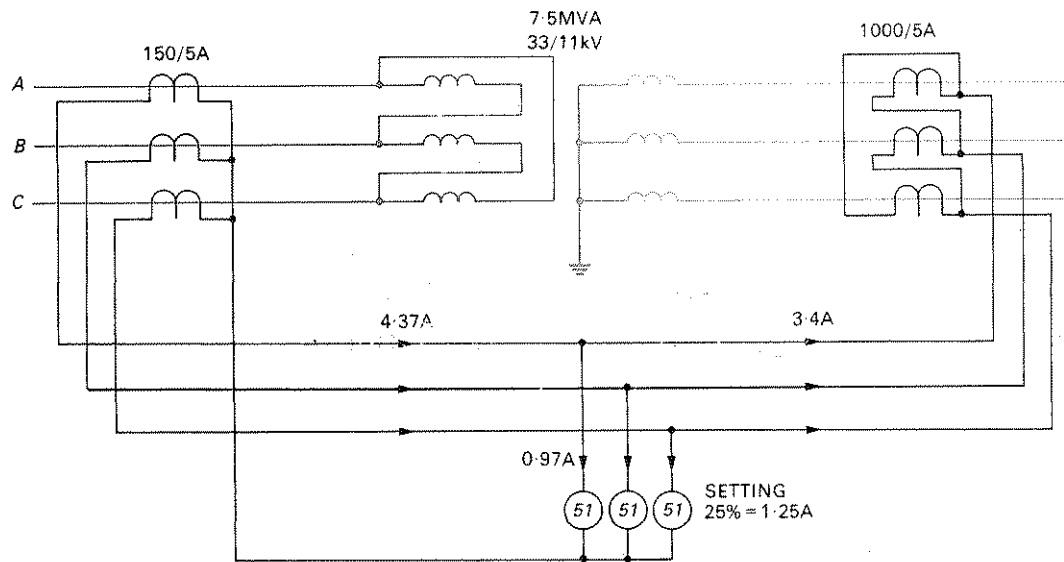
In addition, this scheme does not respond to any fault in a tertiary winding. Unloaded delta-connected tertiary windings are often not protected; alternatively, the delta winding can be earthed at one point through a current transformer which energizes an instantaneous relay.

This system should be separate from the main winding protection. If the tertiary winding earthing lead is connected to the main winding neutral above the neutral current transformer in an attempt to make a combined system, there may be 'blind spots' which the protection cannot cover.

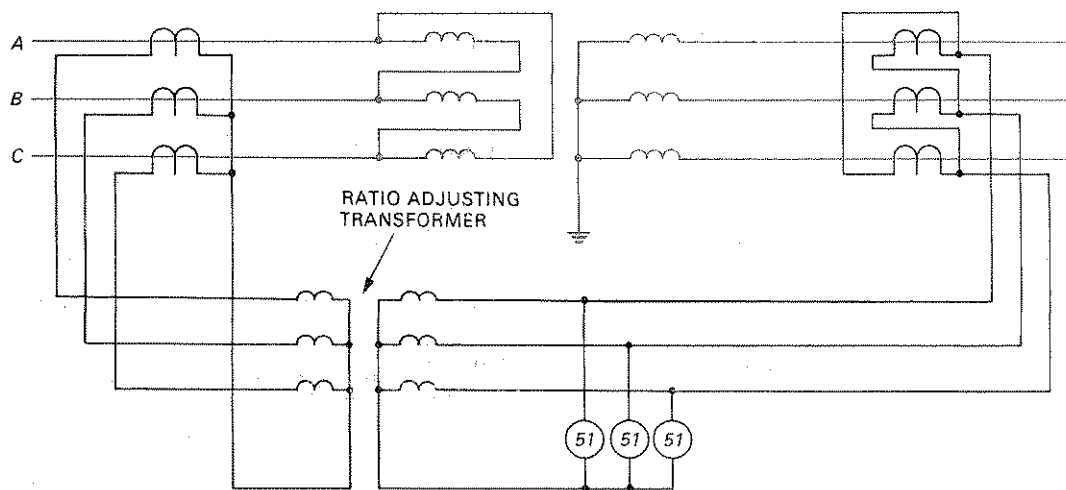
#### 16.9

##### COMBINED DIFFERENTIAL AND RESTRICTED EARTH FAULT SCHEMES

The advantages to be obtained by the use of restricted earth fault protection, discussed in Section 16.6, lead to such a system being frequently used in conjunction with an overall differential system. The importance of this is shown in Figure 16.18 from which it will be seen that if the neutral of a star-connected winding is earthed through a

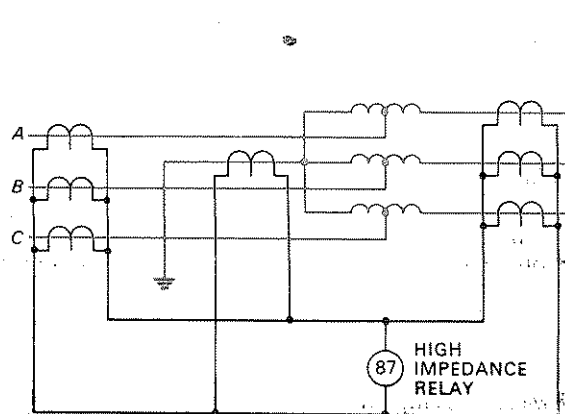


(a) WITHOUT INTERPOSING CURRENT TRANSFORMERS

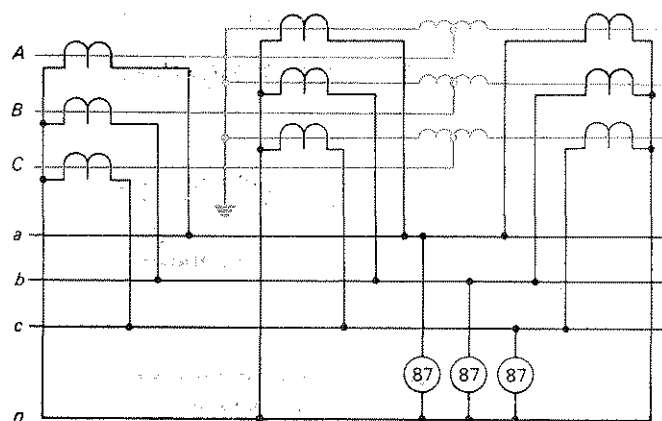


(b) WITH INTERPOSING CURRENT TRANSFORMERS

Figure 16.16 Rough balance protection.



(a) EARTH FAULT SCHEME



(b) PHASE AND EARTH FAULT SCHEME

Figure 16.17 Protection of auto-transformer by high impedance differential relays.

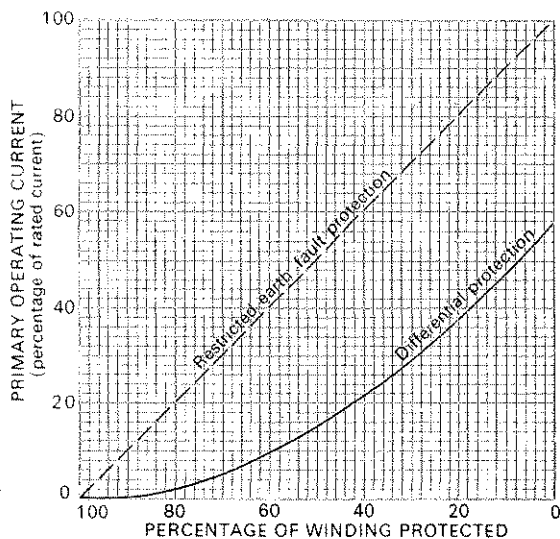


Figure 16.18 Amount of winding protected when transformer is resistance earthed and ratings of transformer and resistor are equal.

resistance of one per unit, an overall differential system having an effective setting of 20% will detect faults in only 42% of the winding from the line end.

The requirements for current transformers are quite different in the two systems in that restricted earth fault

protection uses star-connected current transformers, whereas those for a differential system must be connected in delta on the star side of the transformer. To provide two sets of current transformers would be expensive, but a single set can be used for both duties.

Two alternative methods are available which will enable a single set of line current transformers to be used for both differential protection and restricted earth fault protection of star windings.

One method uses an auxiliary summation current transformer and the other an auxiliary star/delta current transformer. The latter method is more commonly used as it can also provide ratio matching for the differential protection.

### 16.9.1

#### Summation CT scheme

The summation CT, which has four identical primary windings, is connected to the main current transformers and relays as shown in Figure 16.19.

The current transformers are effectively delta-connected with respect to the differential system, the circulating bus wires receiving the vector difference of pairs of phase currents.

The summation CT, however, is energized by individual phase currents, the total summing to zero in the core for balanced conditions. In conjunction with the infeed from the neutral CT, the combination provides a restricted earth fault scheme, responsive only to in-zone residual current.

Thus both the differential and the restricted earth fault systems operate according to their individual characteristics.

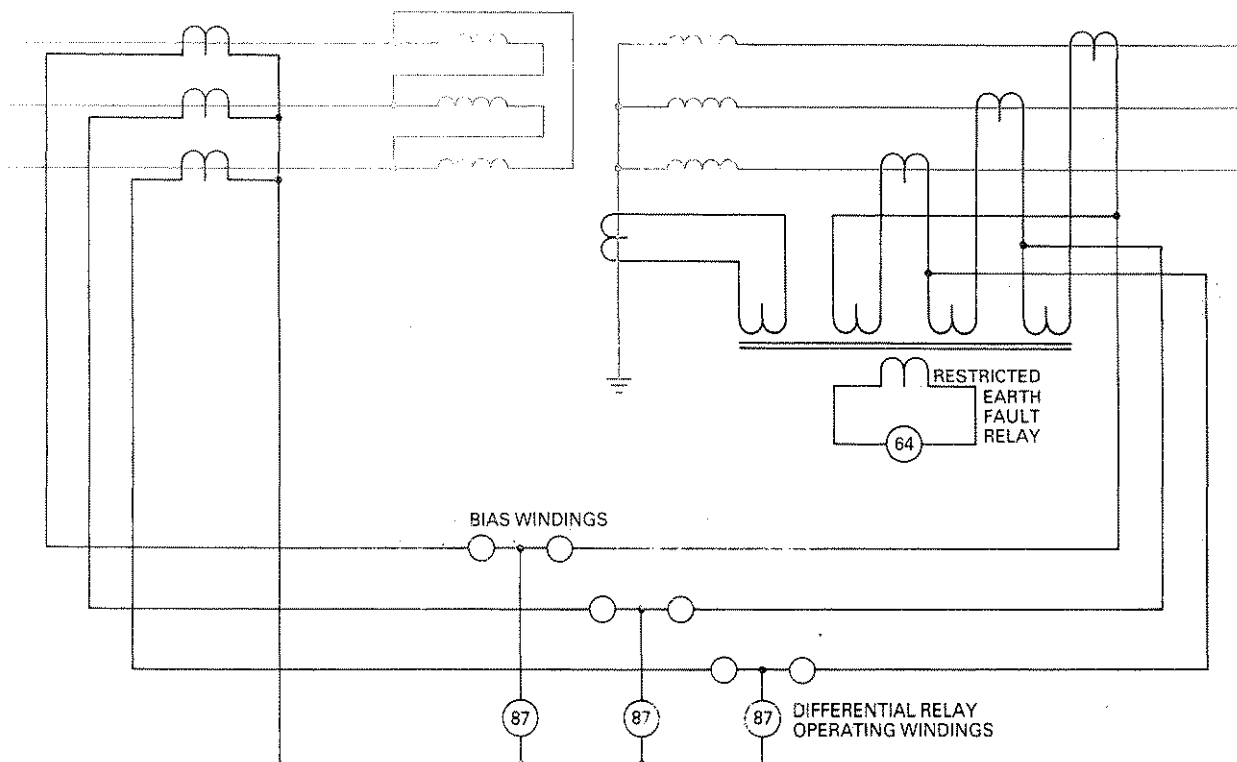


Figure 16.19 Combined differential and earth fault protection using summation auxiliary current transformer.

### 16.9.2

#### Star/delta auxiliary current transformer scheme

When the line current transformers are connected in star, on the star side of the power transformer, as is often preferred, a star/delta group of auxiliary current transformers can be used to restore correct phase conditions for balance. This is shown in Figure 16.20, from which it can be seen that it is also convenient to connect a restricted earth fault relay on the primary side of the auxiliary current transformers.

Although the earth fault and differential relays in the above two schemes cover their respective fault conditions, it must not be thought that their operation is entirely independent. The setting and stability conditions for each must be calculated taking into account all the impedances introduced into the circuit by the auxiliary current transformers and relays.

Moreover, the condition of the main current transformers during in-zone fault conditions is radically different from their state in the through fault condition. As a result, when a heavy inter-phase fault occurs, not only will the differential scheme operate but the restricted earth fault relay is also quite likely to operate because of spill current. This is no detriment to the protection, although the unexpected earth fault indication may confuse subsequent fault analysis. This is a small price to pay for the saving in current transformers which has been achieved.

### 16.9.3

#### Combined differential and REF protection when an earthing transformer is connected within the protected zone

A delta-connected winding cannot deliver any zero

sequence current to an earth fault on the connected system; any current that does flow is in consequence of an earthed neutral elsewhere on the system and will have a 2—1—1 pattern of current distribution between phases.

When the transformer in question represents a major power feed, it may be desired to earth the system at that point, to which end an earthing transformer or earthing reactor is connected to the system, frequently close to the main supply transformer and within the transformer protection zone.

Zero sequence current which flows through the earthing transformer during system earth faults will flow through the line current transformers on this side, and, without an equivalent current in the balancing current transformers, will cause unwanted operation of the relays.

The above condition is corrected by subtracting the appropriate component of current from the main CT output, as shown in Figure 16.21. Such a current is to be found in the neutral conductor of the earthing transformer which carries three times the zero sequence component. Injection into each phase is required, but usually a single CT equal in ratio to the line current transformers is mounted in the neutral circuit. The output of this CT energizes in series three interposing current transformers whose ratio is 1/0.333; the latter transformers are arranged to subtract their output from that of the line current transformers in each phase, thereby cancelling the zero sequence component and restoring balance to the differential system.

A high impedance relay can be connected in the neutral lead between current transformers and differential relays to provide restricted earth fault protection.

As an alternative to the above scheme, the circulating current system can be completed via a three-phase group

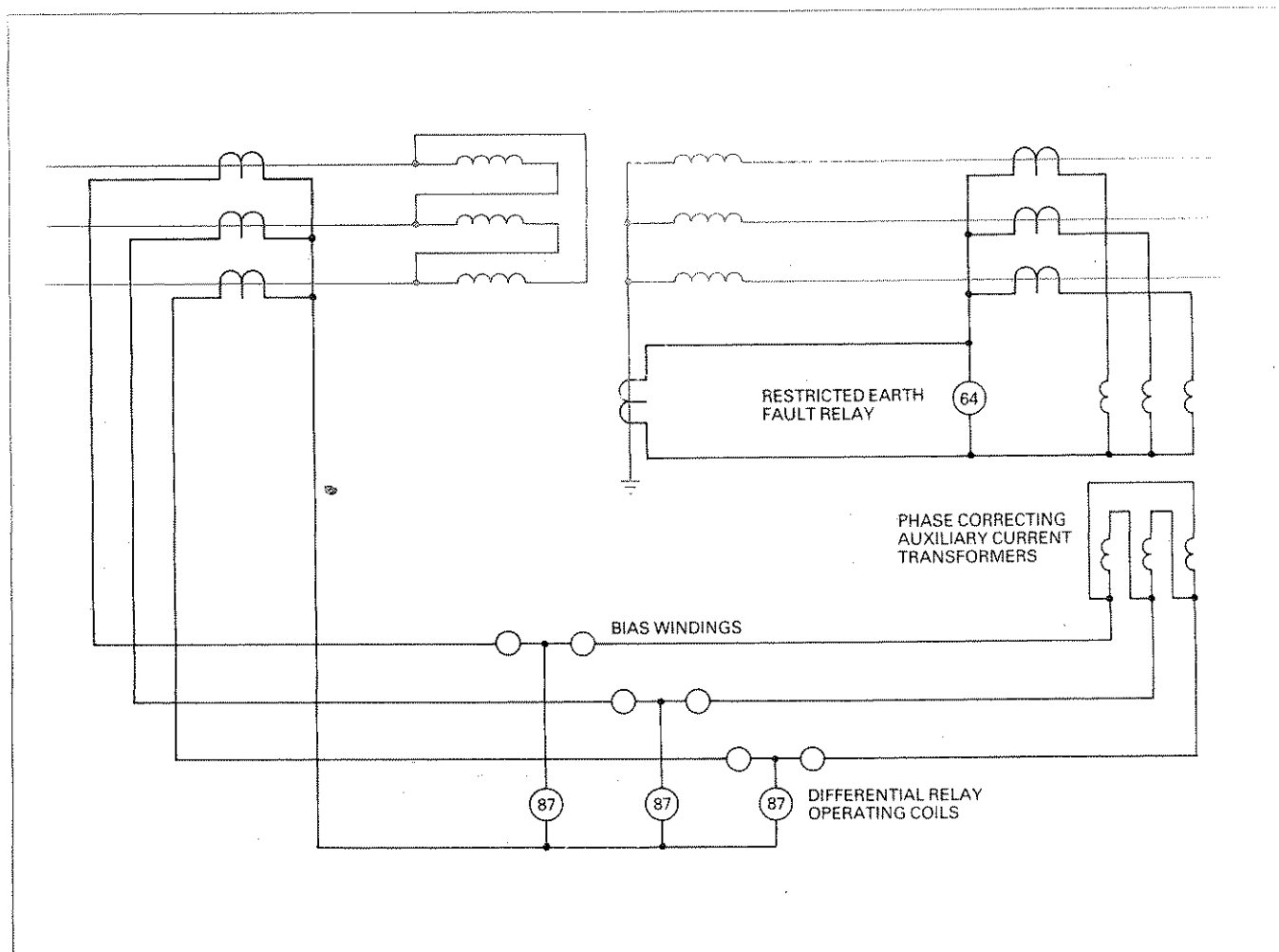


Figure 16.20 Combined differential and restricted earth fault protection.

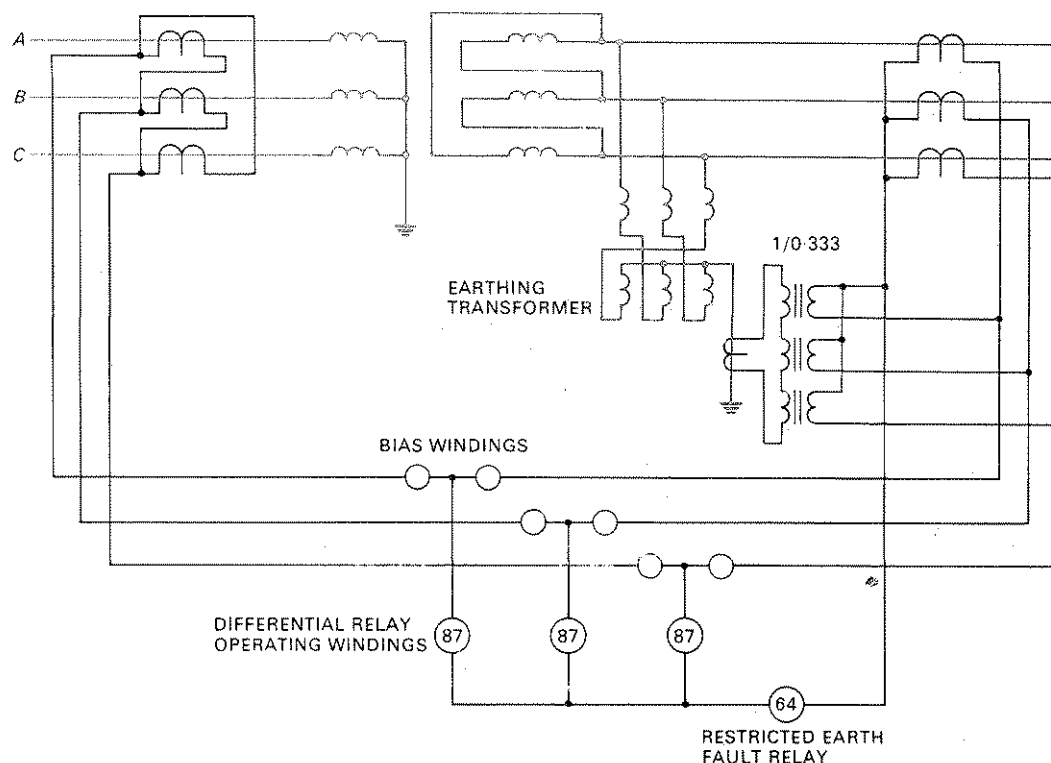


Figure 16.21 Differential protection with in-zone earthing transformer, with restricted earth fault relay.

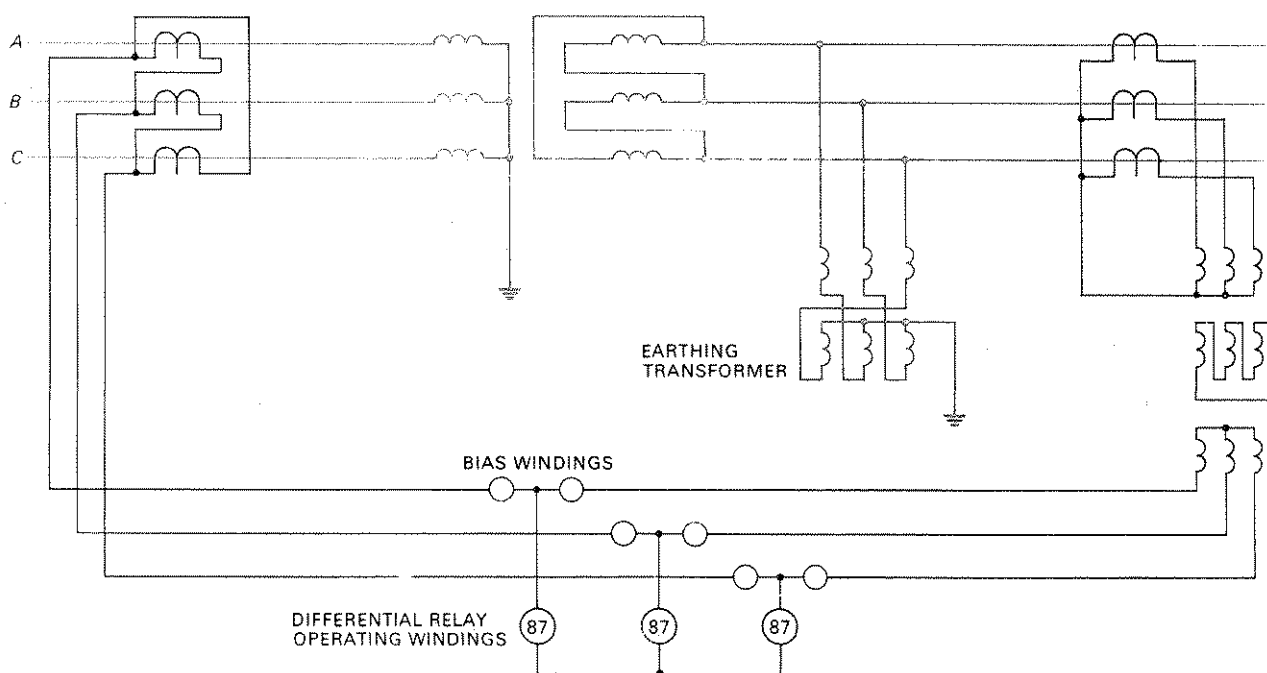


Figure 16.22 Differential protection with in-zone earthing transformer, no earth fault relay.

of interposing transformers which are provided with tertiary windings connected in delta. This winding effectually short-circuits the zero sequence component and thereby removes it from the balancing quantities in the relay circuit; see Figure 16.22.

Provided restricted earth fault protection is not required, the scheme shown in Figure 16.22 has the advantage of not requiring a current transformer, with its associated mounting and cabling requirements, in the neutral-earth conductor. Alternatively the scheme can be connected as

shown in Figure 16.23 when restricted earth fault protection is needed.

#### 16.10 EARTHING TRANSFORMER PROTECTION

The schemes described in the foregoing section refer to an earthing transformer connected within the zone of protec-

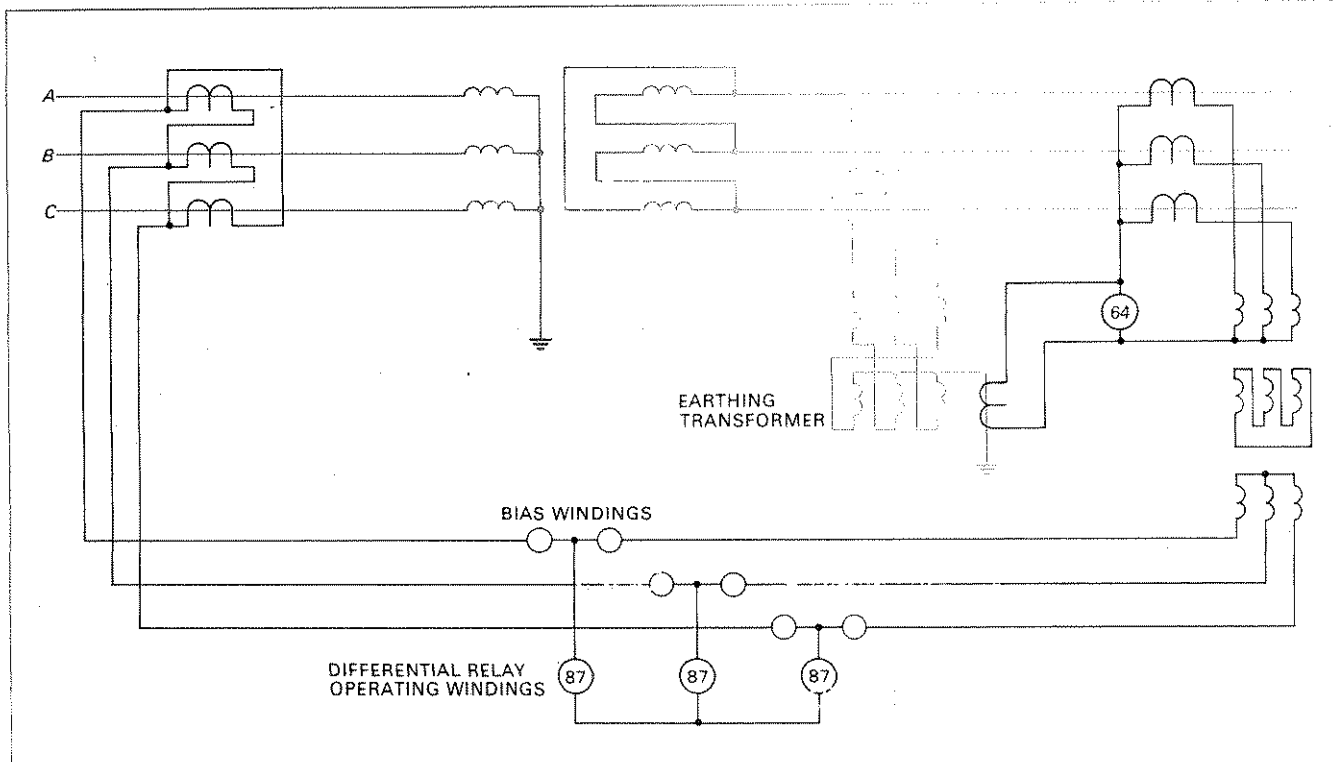


Figure 16.23 Differential protection with in-zone earthing transformer, with alternative arrangement of restricted earth fault relay.

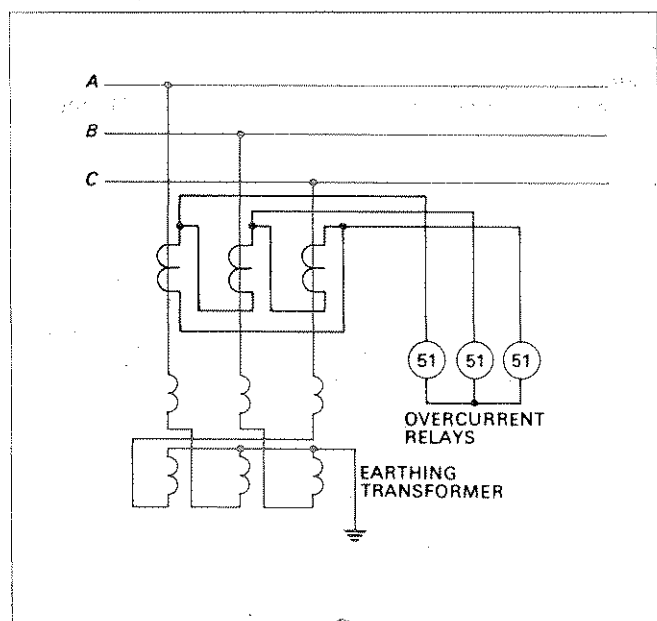


Figure 16.24 Earthing transformer protection.

tion for the main transformer. When it is not so located, it also requires protection, which is arranged as shown in Figure 16.24. The delta-connected current transformers are connected to three I.D.M.T. overcurrent relays. The normal action of the earthing transformer is to pass zero sequence current. The transformed equivalent current circulates in the delta formed by the CT secondaries without energizing the relays. The latter may therefore be set to give fast and sensitive protection against faults in the earthing transformer itself.

### 16.11 OVERFLUXING PROTECTION

The effects of excessive flux density are described in Section 16.2.8. The condition arises only from abnormal operating conditions which are attributable to errors in operation.

The condition does not call for high speed tripping; instantaneous operation is undesirable as this would cause tripping on momentary system disturbances which can be borne safely, but normal conditions must be restored or the transformer must be isolated within one or two minutes at most. The fundamental equation for the generation of e.m.f. in a transformer can be arranged to give:

$$\Phi = K \left( \frac{E}{f} \right)$$

It is necessary to detect a ratio of  $E/f$  exceeding unity,  $E$  and  $f$  being expressed in per unit values of rated quantities.

The system voltage, as measured by a voltage transformer, is applied to a resistance to produce a proportionate current; this current, on being passed through a capacitor, produces a voltage drop which is proportional to the function in question,  $E/f$ , and hence to the flux in the power transformer.

Feedback techniques are used in the type GTT relay to make the measured ratio accurate over a wide range of frequency and voltage.

Two time delay outputs are given by auxiliary elements, each with multiple contacts. One element, the contacts of which are used to effect a control operation to rectify the abnormal condition, operates after a pre-selected fixed time delay between 0.5 s and 1.0 s or between 2 s and 5 s.

The second element is arranged to trip the supplies to the transformer after a pre-set time delay of 5 s to 30 s or 12 s to 120 s if the abnormal condition persists.

Overfluxing protection is mostly confined to generator-transformers for which the risks appear to be greatest, although overfluxing trouble has been known to occur for other transformers as well.

### 16.12 TANK-EARTH PROTECTION

This is also known as Howard protection. If the transformer tank is nominally insulated from earth (an insulation resistance of 10 ohms being sufficient) earth fault protection can be provided by connecting a relay to the secondary of a current transformer the primary of which is connected between the tank and earth. This scheme is similar to the frame-earth fault busbar protection described in Section 15.5.

All faults below oil in a transformer result in the localized heating and breakdown of the oil; some degree of arcing will always take place in a winding fault and the resulting decomposition of the oil will release gases such as hydrogen, carbon monoxide and light hydrocarbons. When the fault is of a very minor type, such as a hot joint, gas is released slowly, but a major fault involving severe arcing causes rapid release of large volumes of gas as well as oil vapour. The action is so violent that the gas and vapour do not have time to escape but instead build up pressure and bodily displace the oil.

When such faults occur in transformers having oil conservators, the fault causes a blast of oil to pass up the relief pipe to the conservator.

Recognition of the above action by Buchholz, and the limitations of other means of detecting certain types of fault, led to the development of the protective device generally known by his name.

Devices responding to abnormally high oil pressure or rate-of-rise of oil pressure are also available and may be used in conjunction with a Buchholz relay.

### 16.13.1

#### Oil pressure relief devices

The simplest form of pressure relief device is the widely used 'frangible disc' which is normally located at the end of an oil relief pipe protruding from the top of the transformer tank.

The surge of oil caused by a serious fault bursts the disc, so allowing the oil to discharge rapidly. By relieving and limiting the pressure rise, explosive rupture of the tank and consequent fire risk is avoided.

A drawback of the frangible disc is that the oil remaining in the tank is left exposed to the atmosphere after rupture. This is avoided in a more effective device, the sudden pressure relief valve, which opens to allow discharge of oil if the pressure exceeds about 10 p.s.i., but closes automatically as soon as the internal pressure falls below the critical level.

If the abnormal pressure is relatively high, this spring-controlled valve can operate within a few milliseconds, and provide fast tripping when suitable contacts are fitted.

Where it is considered essential to avoid the random discharge of oil into the area surrounding the transformer, the discharged oil may be ducted to a catchment pit.

The device is commonly fitted to power transformers rated at 2 MVA or higher, but may be applied to distribution transformers rated as low as 200 kVA, particularly those in hazardous areas.

### 16.13.2

#### Rapid pressure rise delay

This device detects rapid rise of pressure rather than absolute pressure and thereby can respond even quicker than the pressure relief valve to sudden abnormally high pressures. Sensitivities as low as 1 p.s.i./sec are attainable, but when operating in oil the operating speed of the device may have to be slowed deliberately to avoid spurious tripping during circulation pump starts.

### 16.13.3

#### Buchholz protection

The Buchholz relay is contained in a cast housing which is connected in the pipe to the conservator, as in Figure 16.25.

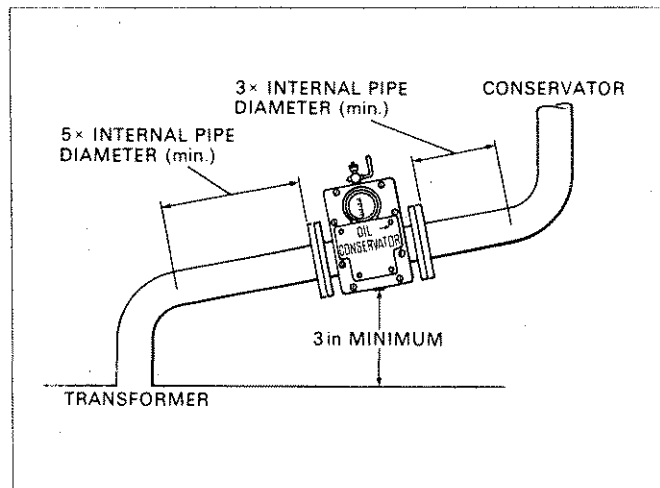


Figure 16.25 Buchholz relay mounting arrangement.

A typical Buchholz relay comprises two pivoted aluminium floats or buckets, each counterbalanced so that with the device empty or completely full of oil the bucket or float is in a high position. Each pivoted bucket assembly carries a mercury switch; see Figure 6.21.

In the normal condition the casing is filled with oil, so that the bucket floats are high and the mercury switches are open. If gas bubbles pass up the piping, they will be trapped in the relay casing, so displacing oil. As the oil level falls the upper float will follow, since the weight of the bucket filled with oil exceeds that of the counterbalance when the buoyancy from the surrounding oil is lost. As the float falls, the mercury switch tilts and closes an alarm circuit.

A similar operation will occur if a tank leak causes the oil level to fall.

The device will therefore give an alarm for the following fault conditions, all of which are of a low order of urgency.

- a. Hot spots on the core due to short circuit of lamination insulation.
- b. Core bolt insulation failure.
- c. Faulty joints.
- d. Interturn faults or other winding faults involving only lower power infeeds.
- e. Loss of oil due to leakage.

When a major winding fault occurs, this causes a surge of oil, which displaces the lower float and thus isolates the transformer. This action will take place for:

- i. All severe winding faults, either to earth or interphase.
- ii. Loss of oil if allowed to continue to a dangerous degree.

The relay is usually provided with an inspection window on either side of the gas collection space, through which the oil level can be observed. This may help in diagnosing the fault. For example, if the gas is white or yellow, insulation has been burnt, while if it is black or grey, dissociated oil is indicated. In these cases the gas will probably be inflammable, whereas released air will not. A petcock is provided on the top of the housing for the gas to be released. If necessary, it can be drawn off and collected for analysis, using a piece of rubber tubing fitted over the release nozzle.

When mounting the relay it is essential to ensure that gas will pass freely up the pipework and also that extra turbulence is not induced in the oil stream. The relay should be mounted with the arrow on the casing pointing to the conservator, in a straight run of pipe which should slope upward from the transformer to the conservator at an angle of 5 degrees. To avoid turbulence, which would alter the effective sensitivity in terms of oil velocity, the pipe should



be straight for at least 5 times the pipe diameter on the transformer side and for three pipe diameters on the conservator side.

Particularly with larger transformers having separate radiators and forced circulation, surges of oil pressure on starting the pumps cause expansion of the radiator tubes, leading to a flow of oil in the conservator pipe. The Buchholz relay must not operate in this circumstance.

When the oil is being cleaned by circulation through centrifuging or filtering plant as part of routine maintenance, aeration takes place, with the result that air is released and collected in the Buchholz relay. It is therefore necessary to disconnect the tripping circuit, leaving the alarm function only, while the oil is being treated and for about 48 hours afterwards. During this period, discretion must be used when dealing with alarm signals.

Because of its universal response to faults within the transformer, some of which are difficult to detect by other means, the Buchholz relay is invaluable, whether regarded as a main protection or as a supplement to other protection schemes. Tests carried out with simulated operating conditions, that is, by striking a high voltage arc in a transformer tank filled with oil, have shown that operation in the time range 0.05–0.1 s is possible. Electrical protection is generally used as well, either to obtain faster operation for heavy faults, or because Buchholz relays have to be prevented from tripping during oil maintenance periods. Nevertheless, Buchholz relays are included in the protection schemes of all transformers fitted with conservators, in British and European practice. Transformers without conservators (usually of less than 1000 kVA rating) cannot be provided with Buchholz protection.

## 16.14 TRANSFORMER-FEEDER PROTECTION

A transformer-feeder comprises a transformer directly connected to a transmission circuit without the intervention of switchgear. Examples are shown in Figure 16.26.

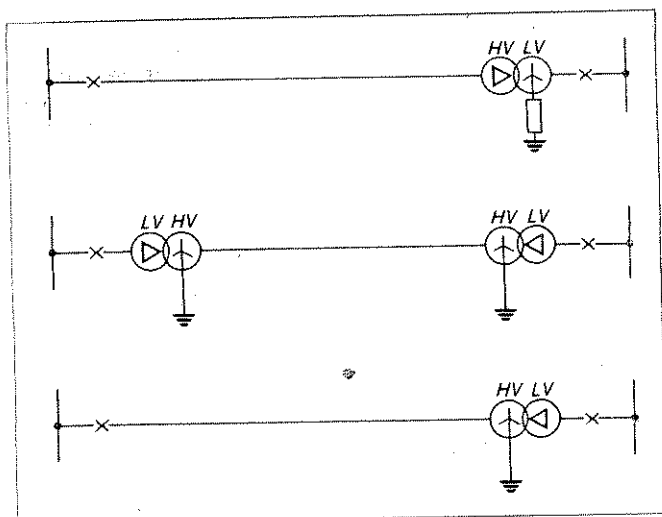


Figure 16.26 Typical transformer-feeder circuits.

The saving in switchgear so achieved is offset by increased complication in the necessary protection. The primary requirement is intertripping, since the feeder protection remote from the transformer will not respond to the low current fault conditions which can be detected by restricted earth fault and Buchholz protections.

Either unrestricted or restricted protection can be applied; moreover, the transformer-feeder can be protected as a single zone or be provided with separate protections for the feeder and the transformer. In the latter case, the separate protections can both be unit type systems. An alternative,

which is normally adequate, is the combination of unit transformer protection with an unrestricted system of feeder protection, plus an intertripping feature.

### 16.14.1

#### Non-unit schemes

##### Feeder phase and earth faults

High speed protection against phase and earth faults can be provided by distance relays located at the end of the feeder remote from the transformer. The first zone of a distance scheme applied to a simple feeder would be set to reach only 80–85% of the feeder length, the margin being to allow for various errors in measurement. In the case of a transformer-feeder, the transformer constitutes an appreciable lumped impedance. It is therefore possible to set a distance relay zone to cover the whole feeder and reach part way into the transformer impedance. With a normal tolerance on setting thus allowed for, it is possible for fast zone 1 protection to cover the whole of the feeder with certainty without risk of over-reaching to a fault on the low voltage side.

Although the distance zone is described as being set 'half way into the transformer', it must not be thought that half the transformer winding will be protected. The effects of auto-transformer action and variations in the effective impedance of the winding with fault position prevent this, making the amount of winding beyond the terminals which is protected very small. The value of the system is confined to the feeder, which, as stated above, receives high speed protection throughout.

##### Feeder phase faults

A distance scheme is not, for all practical purposes, affected by varying fault levels on the high voltage busbars and is therefore the best scheme to apply if the fault level may vary widely. In cases where the fault level is reasonably constant, similar protection can be obtained using high set instantaneous overcurrent relays, provided these have a low transient over-reach.

Transient over-reach is defined as:

$$\frac{I_s - I_F}{I_F} \times 100\%$$

where  $I_s$  = setting current, that is, r.m.s. value of steady state current required to operate the relay.

$I_F$  = steady state r.m.s. value of the fault current which when fully offset will just operate the relay.

The instantaneous overcurrent relays must be set without risk of them operating for faults on the remote side of the transformer.

Referring to Figure 16.27, the required setting to ensure that the relay will not operate for a fully offset fault  $I_{F2}$  is given by:

$$I_s = 1.2 (1 + t) I_{F2}$$

where  $I_{F2}$  is the fault current under maximum source conditions, that is, when  $Z_s$  is minimum, and the factor of 1.2 covers possible errors in the system impedance details used for calculation of  $I_{F2}$ , together with relay and CT errors.

As it is desirable for the instantaneous overcurrent protection to clear all phase faults anywhere within the feeder under varying system operating conditions, it is necessary to have a relay setting less than  $I_{F1}$  in order to ensure fast and reliable operation.

Let the setting ratio resulting from setting  $I_s$  be

$$r = \frac{I_s}{I_{F1}}$$

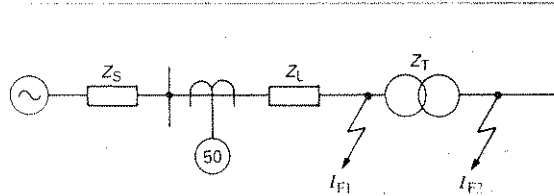
Therefore

$$r I_{F1} = 1.2 (1 + t) I_{F2}$$

$$r = 1.2 (1 + t) \frac{Z_S + Z_L}{Z_S + Z_L + Z_T}$$

$$= 1.2 (1 + t) \frac{Z_S + Z_L}{(1 + x) (Z_S + Z_L)}$$

$$= \frac{1.2 (1 + t)}{1 + x}$$



|                             |      | SETTING RATIO $r = \frac{I_{F1}}{I_{F2}}$ |      |      |      |
|-----------------------------|------|-------------------------------------------|------|------|------|
| TRANSIENT OVER-REACH (%)    |      | 5                                         | 25   | 50   | 100  |
| $x = \frac{Z_T}{Z_S + Z_L}$ | 0.25 | 1.01                                      | 1.20 | 1.44 | 1.92 |
|                             | 0.5  | 0.84                                      | 1.00 | 1.20 | 1.60 |
|                             | 1.0  | 0.63                                      | 0.75 | 0.90 | 1.20 |
|                             | 2.0  | 0.42                                      | 0.50 | 0.60 | 0.80 |
|                             | 4.0  | 0.25                                      | 0.30 | 0.36 | 0.48 |
|                             | 8.0  | 0.14                                      | 0.17 | 0.20 | 0.27 |

$I_r$  = Relay setting =  $1.2 (1 + t) I_{F2}$   
 $t$  = Transient over-reach (p.u.)

Figure 16.27 Over-reach considerations in the application of transformer-feeder protection.

The setting ratios resulting from relays having different transient overreach characteristics and set so as not to operate for  $I_{F2}$  are tabulated in Figure 16.27 for different transformer impedance values  $Z_T$  where

$$x = \frac{Z_T}{Z_S + Z_L}$$

It can be seen that for a given transformer size, the most sensitive protection for the line will be obtained by using relays with the lowest transient overreach. It should be noted that where  $r$  is greater than 1, the protection will not cover the whole line. Also, any increase in source impedance above the minimum value will increase the effective setting ratios above those shown. Relays with low transient overreach such as types CAG19 and CAG17 will give more satisfactory cover to the feeder, with a better setting margin than relays which have no transient immunity.

The instantaneous protection is usually applied with a time delayed overcurrent relay having a lower current setting. In this way, instantaneous protection is provided for the feeder, with the time delayed relay covering faults on the transformer.

When the power can flow in the transformer-feeder in either direction, overcurrent relays will be required at both ends. In the case of parallel transformer-feeders, it is essential that the overcurrent relays on the low voltage side be directional, operating only for fault current fed into the transformer-feeder. This is necessary because the relays in both circuits will have the same time and current settings and would therefore both operate for a fault in one circuit

unless the directional control were also used. A parallel feeder is the limiting case of the ring main (see Section 9.19).

### Earth faults

Instantaneous restricted earth fault protection is normally provided. When the high voltage winding is delta connected, a relay in the residual circuit of the line current transformers gives earth fault protection which is fundamentally limited to the feeder and the associated delta-connected transformer winding, the latter being unable to transmit any zero sequence current to a through earth fault.

When the feeder is associated with an earthed star-connected winding, normal restricted earth fault protection as described in Section 16.6 is not applicable because of the remoteness of the transformer neutral.

Restricted protection can be applied using a directional earth fault relay. A simple sensitive and high speed directional relay can be used, but if it is, great attention must be paid to the transient stability of the element. Alternatively, a directional I.D.M.T. relay may be used, the time multiplier being set low. The slight inverse time delay in operating will ensure that unwanted transient operation is not a trouble.

When the supply source is on the high voltage star side an alternative scheme that does not require a voltage transformer can be used. The scheme is shown in Figure 16.28. For the circuit breaker to trip, both relays  $G$  and  $H$  must operate, which will occur for earth faults on the feeder or transformer winding.

External earth faults cause the transformer to deliver zero sequence current only, which will circulate in the closed delta connection of the secondary windings of the three auxiliary current transformers. No output is available to relays  $H$ . Through phase faults will operate one or more of relays  $H$ , but not the residual relay  $G$ , so no through fault causes operation.

Relays  $H$  must have settings above the maximum load. As the earthing of the neutral at a receiving point is likely to be solid and the earth fault current will therefore be comparable with the phase fault current, high settings are not a serious limitation.

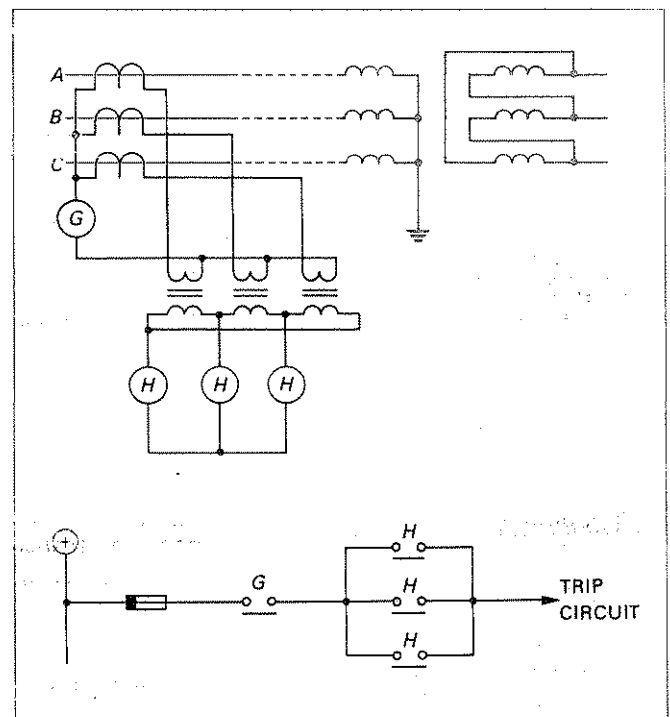


Figure 16.28 Instantaneous protection of transformer-feeder.

Earth fault protection of the low voltage winding will be provided by a restricted earth fault system using either three or four current transformers, according to whether the winding is delta or star-connected, as described in Section 16.6.

#### *In-zone capacitance*

The feeder portion of the transformer-feeder will have an appreciable capacitance between each conductor and earth. During an external earth fault the neutral will be displaced, and the resulting zero sequence component of voltage will produce a corresponding component of zero sequence capacitance current. In the limiting case of full neutral displacement, this zero sequence current will be equal in value to the normal positive sequence current.

The resulting residual current is equal to three times the zero sequence current and hence to three times the normal line charging current.

The value of this component of in-zone current should be considered when establishing the effective setting of earth fault relays.

### 16.14.2

#### Unit schemes

The basic differences between the requirements of feeder and transformer protections lie in the limitation imposed on the transfer of earth fault current by the transformer and the need for high sensitivity in the transformer protection, suggesting that the two components of a transformer-feeder should be protected separately. This involves mounting current transformers adjacent to, or on, the high voltage terminals of the transformer. Separate current transformers are desirable for the feeder and transformer protections so that these can be arranged in two separate overlapping zones. The use of common current transformers is possible, but may involve the use of auxiliary current transformers, or special winding and connection arrangements of the relays. In any case, the common current transformers would have to be large enough for the combined burden, so that little saving, if any, would be achieved.

Intertipping of the remote circuit breaker from the transformer protection will be necessary, but this can be done using the pilots of the feeder protection.

Although technically superior, the use of separate protective systems is seldom justifiable when compared with an overall system or a combination of non-unit feeder protection and a unit transformer system.

An overall differential system must take into account the fact that zero sequence current on one side of a transformer may not be reproduced in any form on the other side. Summation windings as used for feeder protection and described in Section 10.6 are not, therefore, appropriate.

The line current transformers can be connected to a tapped winding, as shown in Figure 16.29, an arrangement which produces an output for phase faults. Some response also occurs for A and B phase-earth faults, but the resulting settings will be similar to those for phase faults and no protection will be given for C phase-earth faults. Separate earth fault protection must therefore be added on both sides of the transformer using the usual techniques; see Section 16.9.

The two winding sections on the summation transformers have an unequal number of turns, so as to provide an operating quantity with the 1—2—1 primary phase current distribution which would arise from a phase to phase fault on the other side of the transformer. If the winding had equal sections there would be an ampere-turn balance

produced in the primary of this CT with no resultant output.

Response to this current distribution is obtained only with the penalty of a wider range of fault settings for all other conditions.

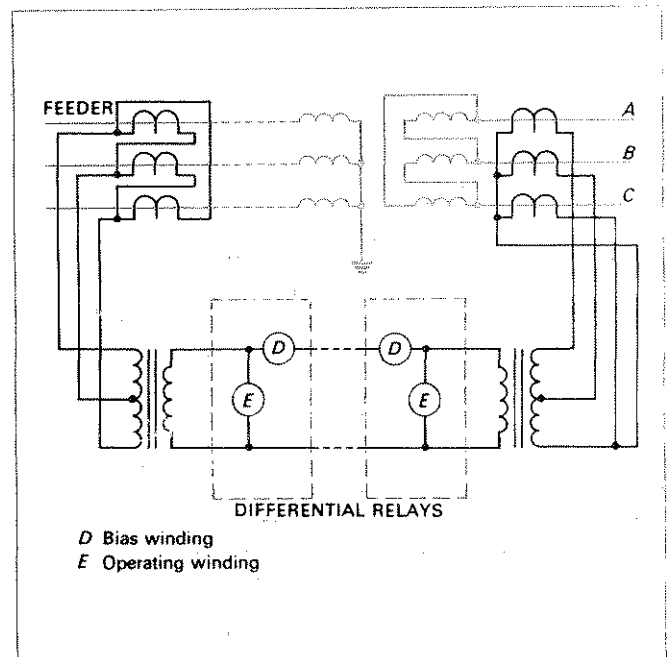


Figure 16.29 Overall protection for transformer-feeder (circulating current type; restricted earth fault schemes not shown).

An alternative technique is shown in Figure 16.30.

The B phase is taken through a separate winding on another transformer or relay electromagnet, to provide another balancing system. The two transformers are interconnected with their counterparts at the other end of the feeder-transformer by four pilot wires. Operation with three pilot cores is possible but four are preferable, involving little increase in pilot cost.

The interconnection with current transformers as well as the design of the relay must comply with the conditions set out in Section 16.7.

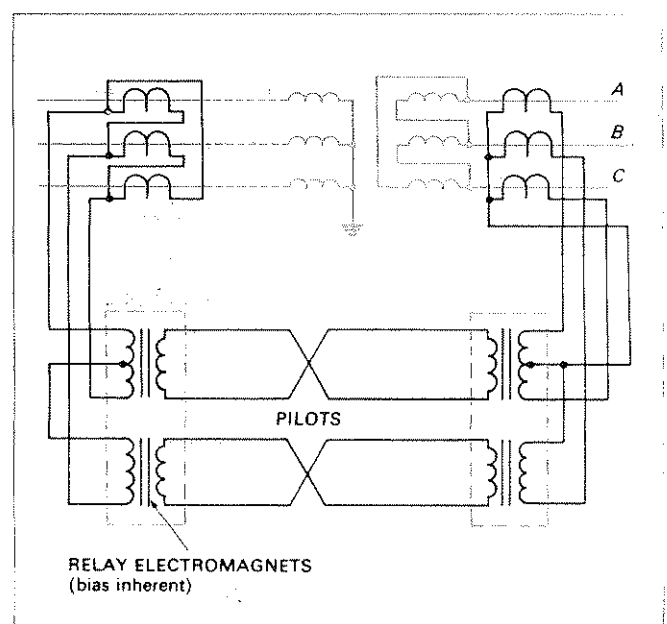


Figure 16.30 Overall differential protection for transformer feeder; electromechanical Translay balanced voltage system.

A typical system is the Translay HHTA4 protection. The summation windings are carried on the relay electromagnets. The relays are generally similar to the Translay feeder protection described in Section 10.8.1, except that the relays each have two elements, wound as Figure 16.30, and are designed for a longer travel, which is adjustable, like that of an I.D.M.T. overcurrent relay.

The scheme provides phase and earth fault settings of 55%. The maximum operating time is 1.5 seconds with an applied current of five times the setting; the time is adjustable by a time multiplier head calibrated 0—1.0. A time multiplier setting of 0.1 or 0.15 will usually be found to be sufficient to give stability against inrush.

The relay has a bias characteristic sufficient to cater for a normal tapping range on the power transformer.

Restricted earth fault relays can be added to either or both sides of the above scheme by the methods described in Section 16.9.

The transformer will also be provided with Buchholz protection, overfluxing protection if necessary, overload or overheating protection, and so on.

An alternative biased differential scheme employing pilot wire conductors between line ends, is based on the Translay 'S' protection described in Section 10.8.4. By including a relay, type MCTH, to detect when power transformer magnetizing inrush currents are present, the Translay 'S'

protection can be applied for the protection of transformer feeders also.

When the in-zone transformer is energized the resulting inrush current will be detected by the MCTH relay which will then short circuit the pilot wires of the Translay 'S' relay. This will stabilize the differential relay and prevent it from responding to what would otherwise appear to be an in-zone fault.

The MCTH relay has built-in overcurrent detectors, which are arranged to over-ride the blocking feature if a fault is detected in one phase whilst inrush is present in another.

The scheme is shown in Figure 16.31, applied to provide overall protection to a feeder terminated by a delta-star power transformer. At the star winding of the latter the CTs are connected in delta in the conventional manner, but the A, B and C phase secondary circuits are taken to the relay terminals normally used for A, C and N respectively, to ensure suitable sensitivity to earth faults.

When, for reasons of balance, the same relay connections are applied at the other line end, it may be seen that no secondary current will be directed to the Translay differential relay from star connected line CTs for B-E faults on the feeder. So a high impedance differential relay, type MFAC, is connected in the secondary neutral circuit, to cover these faults, and is arranged to intertrip the remote circuit breakers also.

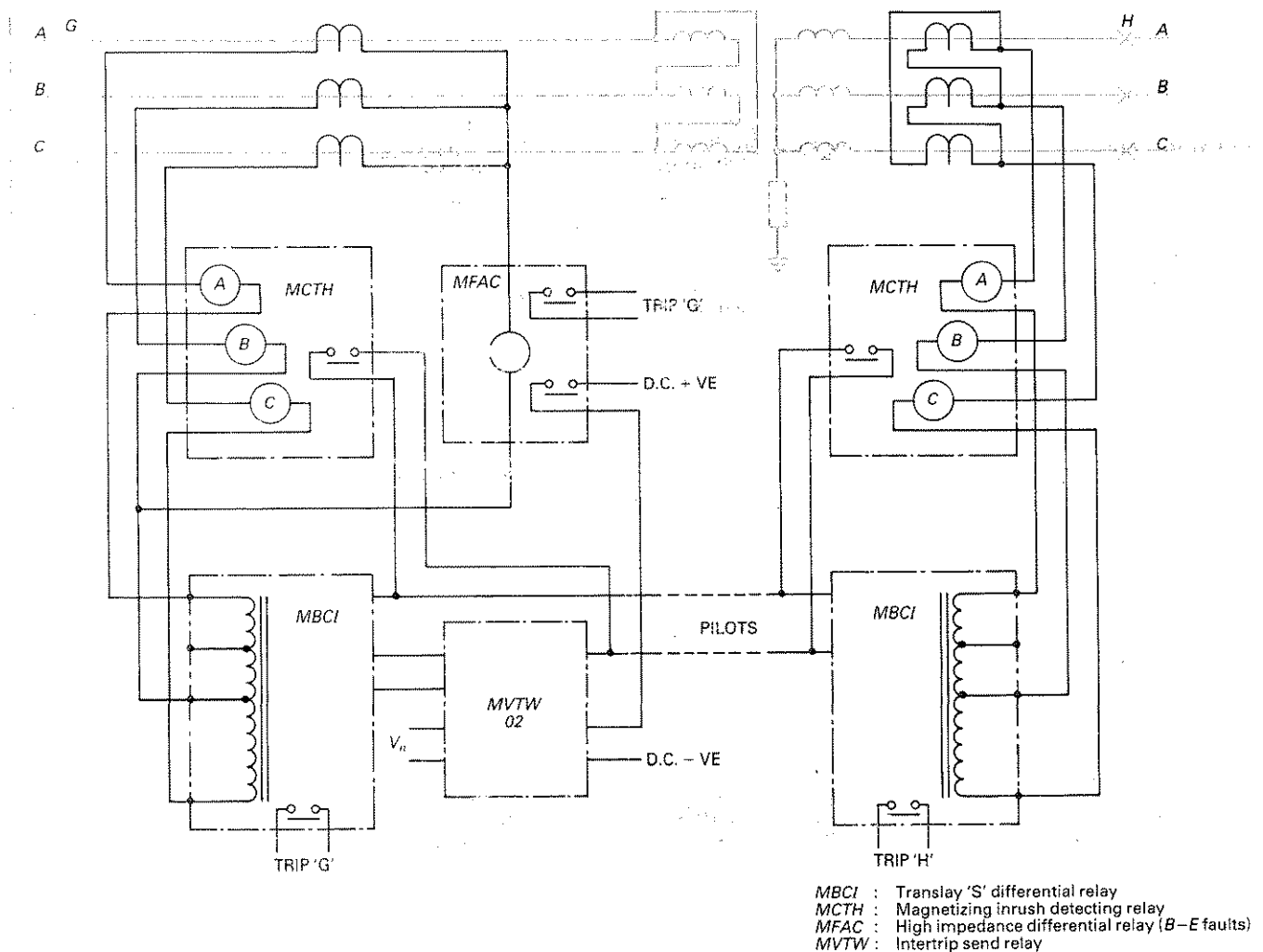


Figure 16.31 Transformer feeder protection using Translay 'S' differential relay with magnetizing inrush detecting relay.

## 16.15

### INTERTRIPPING

In order to ensure that both the high and low voltage circuit breakers operate for faults within the transformer and feeder, it is necessary to operate both circuit breakers from protection normally associated with one. The technique for doing this is known as intertripping.

The necessity for intertripping on transformer-feeders arises from the fact that certain types of fault produce insufficient current to operate the protection associated with one of the circuit breakers. These faults are:

- Faults in the transformer which operate the Buchholz relay and trip the local low voltage circuit breaker, while failing to produce enough fault current to operate the protection associated with the remote high voltage circuit breaker.
- Earth faults on the star winding of the transformer, which, because of the position of the fault in the winding, again produce insufficient current for relay operation at the remote circuit breaker.
- Earth faults on the feeder or high voltage delta-connected winding which trip the high voltage circuit breaker only, leaving the transformer energized from the low voltage side and with two high voltage phases at near line-to-line voltage above earth. Intermittent arcing may

follow, and there is a possibility of transient overvoltage occurring and causing a further breakdown of insulation. Several methods are available for intertripping; these are discussed in Chapter 18.

#### 16.15.1

##### Neutral displacement

An earth fault occurring on the feeder connected to an unearthed transformer winding should be cleared by the feeder circuit breaker, but if there is also a source of supply on the low voltage side of the transformer, the feeder may be maintained alive. The feeder will then be a local unearthed system, and, if the earth fault continues in an arcing condition, dangerous overvoltages may occur.

An alternative to intertripping is to detect the condition by measuring the residual voltage on the feeder.

A voltage relay is energized from the broken-delta connected secondary winding of a voltage transformer on the high voltage line, and receives an input proportional to the zero sequence voltage of the line, that is, to any displacement of the neutral point; see Figure 16.32.

The relay normally receives zero voltage, but, in the presence of an earth fault, the broken-delta voltage will rise to three times the phase voltage. Earth faults elsewhere in the system may result in displacement of the neutral. The degree of displacement will depend on the zero sequence voltage distribution in the system, but is generally highest when the system is insulated or resistance earthed. To obtain discrimination it is necessary to use an inverse time or definite time neutral displacement overvoltage relay. Inverse time relays types VDG12 or MVTU13 and definite time relay MVTU13 can be used for this purpose. Time and voltage settings are chosen to discriminate with protection elsewhere on the system.

An alternative to using a high voltage transformer is shown in Figure 16.33. In this case, three high voltage capacitors are connected in star to the line and the residual current is measured by a sensitive relay in the earthing lead from the neutral point.

The capacitors can be tapped bushings used, for example, as the high voltage terminals of the transformer. The relay may be either of rectified moving coil or electronic type, and a time delay must be introduced for discrimination as before.

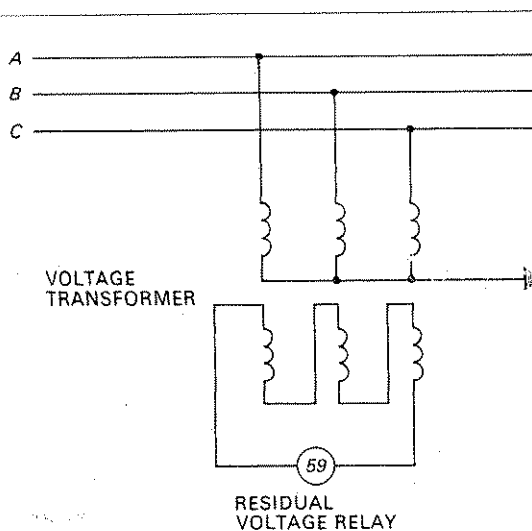


Figure 16.32 Neutral displacement detection using voltage transformer.

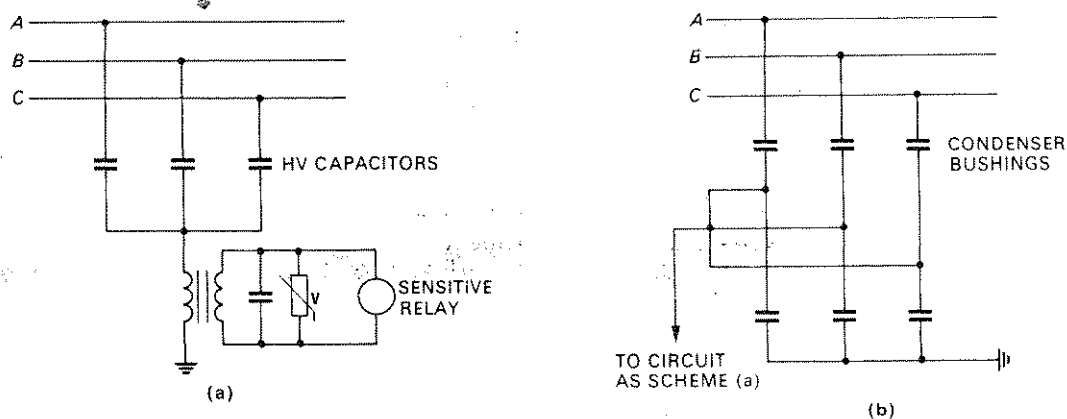


Figure 16.33 Neutral displacement detection using high voltage capacitors.



# Generator and generator-transformer protection

- 17.1 Introduction.
- 17.2 Lightning and earth faults.
- 17.3 Phase faults.
- 17.4 Stator faults.
- 17.5 Fielding protection.
- 17.6 Stator fault protection of the stator winding.
- 17.7 Overload protection.
- 17.8 Overcurrent protection.
- 17.9 Backup earth fault protection.
- 17.10 Undervoltage protection.
- 17.11 Unbalanced loading.
- 17.12 Rotor faults.
- 17.13 Synchronous running and pole slipping.
- 17.14 Earth fault.
- 17.15 Mechanical faults.
- 17.16 Complete protection scheme.
- 17.17 Field suppression.

## 17.1

### INTRODUCTION

The core of an electrical power system is the generator. The conversion of the fundamental energy into its electrical equivalent requires a 'prime mover' to develop mechanical power as an intermediate stage. The nature of this machine depends upon the source of energy and in turn this has some bearing on the design of the generator. There are power units based on steam, gas, water power and diesel engine drive.

The range of size extends from a few hundred kVA (or even less) for engine-driven and hydro sets up to turbine-driven sets exceeding 500 MVA in rating.

Small and medium sized sets may be directly connected to the distribution system. A larger unit is usually associated with an individual transformer, through which the set is coupled to the EHV primary transmission system. No switchgear is provided between the generator and transformer, which are treated as a unit; a unit transformer may be tapped off the interconnection for the supply of power to auxiliary plant. A typical arrangement is shown in Figure 17.1.

A modern generating unit is a complex system comprising the generator stator winding and associated transformer and unit transformer, the rotor with its field winding and exciters, and the turbine and its associated condenser and boiler complete with auxiliary fans and pumps. Faults of many kinds can occur within this system for which diverse

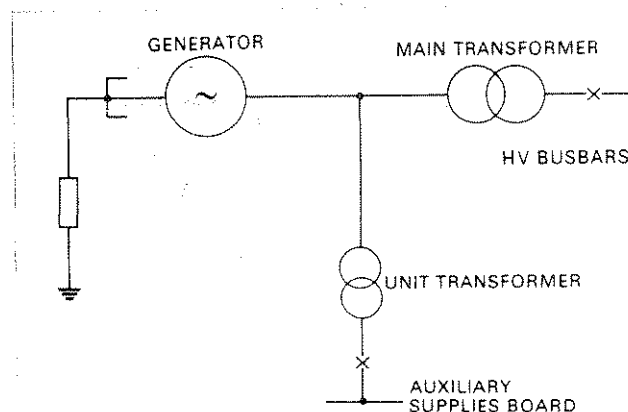


Figure 17.1 Generator-transformer unit.

protective means are needed. The amount of protection applied will be governed by economic considerations, taking into account the value of the machine and its importance to the power system as a whole.

The following hazards require consideration:

- a. Stator insulation faults
- b. Overload
- c. Overvoltage
- d. Unbalanced loading
- e. Rotor faults
- f. Loss of excitation
- g. Loss of synchronism
- h. Failure of prime mover
- i. Low vacuum
- j. Lubrication oil failure
- k. Loss of boiler firing
- l. Overspeeding
- m. Rotor distortion
- n. Difference in expansion between rotating and stationary parts
- o. Excessive vibration

## 17.2

The neutral point of a generator is usually earthed, so as to facilitate protection of the stator winding and associated system. Impedance is inserted in the earthing lead to limit the magnitude of earth fault current. Severe arcing to the machine core burns the iron at the point of fault and welds laminations together. Replacement of the faulty conductor may not be a very serious matter but the damage to the core cannot be ignored, since the welding of laminations would most likely result in local overheating. The fused metal can sometimes be cut away and replaced, but if severe damage has occurred, it may be necessary to rebuild the core down to the fault, which would involve extensive dismantling of the winding. Practice as to the degree of fault current limitation varies from approximately rated current on the one hand to comparatively low values on the other. One authority asserts that, provided the earth fault current does not exceed 5A, burning of the core will not readily occur, although it appears that the type of conductor insulation also has a bearing on this matter.

Generators which are directly connected to a transmission or distribution system are usually earthed through a resistance which will pass approximately rated current to a terminal earth fault. A few machines have been installed, however, in which the earth fault current was limited to a few amperes, in line with the above principle.

In the case of a generator-transformer unit, the generator winding and primary winding of the transformer can be treated as an isolated system which is not influenced by the earthing requirements of the transmission system. It is not desirable that such a system should be entirely 'floating' in potential, and a common practice formerly applied was to earth the neutral through the primary winding of a voltage transformer; the secondary winding was then used to energize alarm devices to signal the existence of an earth fault. This is now considered to be unsafe practice, because enough capacitance can exist in the machine winding and the connections to the transformer to cause a build-up of dangerous overvoltages in the event of an arcing earth fault. Moreover, the capacitance effect may also prevent the earth fault current from being limited to the very low value corresponding to the magnetizing current of the voltage transformer. Normal modern practice is to use a larger earthing transformer rated in the range 5–100 kVA. The secondary winding, which is designed for medium voltage (100–500 volts), is loaded with a resistor of a value which, when referred through the transformer ratio, will pass a suitable fault current. The resistor is therefore of low ohmic value and can be of rugged construction while still presenting a high equivalent value in the generator circuit.

The resistor has been introduced to prevent the production of high transient overvoltages in the event of an arcing earth fault, which it does by discharging the bound charge in the circuit capacitance. For this reason, the equivalent resistance in the stator circuit should not exceed the impedance at system frequency of the total summated capacitance of the three phases. In other words, the resistive component of fault current should not be less than the residual capacitance current, that is,  $3I_{co}$ . This is a basis of the design; in some territories a larger fault current of up to five times the above value is permitted.

It is important that the earthing transformer never becomes saturated, otherwise a very undesirable condition of ferro-resonance may occur. The normal rise of the generated voltage above the rated value caused by a sudden loss of load or by field forcing must be considered, as well as flux doubling in the transformer due to the point-on-wave of voltage application. It is sufficient that the transformer be designed to have a primary winding knee-point e.m.f. equal to 1.3 times the generator rated line voltage.

Earth fault protection can be obtained by applying a relay to measure the transformer secondary current or by connecting a voltage measuring relay in parallel with the loading resistor; see Section 17.9.2.

The above arrangement, which is commonly known as 'distribution transformer earthing' is illustrated by the following example.

### 17.2.1

#### Example of earthing by distribution transformer

##### Generator:

|                     |                        |
|---------------------|------------------------|
| Rated output        | 120 MW                 |
| Rated voltage       | 13.8 kV                |
| Maximum overvoltage | 18 kV                  |
| Winding capacitance | 0.22 $\mu$ F per phase |

##### Generator-transformer:

|                             |                         |
|-----------------------------|-------------------------|
| Rated voltage               | 143.6/13.8 kV           |
| Primary winding capacitance | 0.006 $\mu$ F per phase |

##### Total capacitance per phase:

|                            |               |
|----------------------------|---------------|
| Generator                  | 0.22 $\mu$ F  |
| Generator connections      | 0.001 $\mu$ F |
| Generator-transformer (LV) | 0.006 $\mu$ F |
| Total                      | 0.227 $\mu$ F |

When the interconnection is made by cable, the capacitance value of the connections will be much greater, although not usually affecting the total by much. Where surge protection capacitors or surge arresters are fitted, these must be included.

$$\begin{aligned}
 \text{Total residual capacitance} &= 3C \\
 \text{Residual capacitive impedance} &= \frac{10^6}{3\omega C} \\
 &= \frac{10^6}{314 \times 0.681} \\
 &= 4680 \text{ ohms}
 \end{aligned}$$

If the effective earthing resistance is made equal to the total residual capacitive impedance of 4680 ohms, then, with a generator terminal fault at normal voltage, the neutral current is:

$$\frac{13,800}{\sqrt{3} \times 4680} = 1.7 \text{ A}$$

The actual fault current will contain equal resistive and capacitive components and will therefore be:

$$1.7 + j1.7 = 2.4 \text{ A}$$



### Earthing transformer

The primary knee-point voltage should not be less than  $1.3 \times 13.8$ , that is, 18 kV. The applied voltage during an earth fault is normally  $13.8/\sqrt{3}$ , that is, 8 kV, and with field forcing may be 10.4 kV. Hence, in either case, standard 11 kV insulation will be satisfactory.

The maximum neutral current will be increased under field forcing conditions in proportion to the voltage rise and will therefore be:

$$\frac{10.4}{8} \times 1.7 = 2.2 \text{ A}$$

Hence, the maximum loading under such conditions is  $2.2 \times 10.4$ , that is, 22.9 kVA. A 30 seconds rating for maximum duty is more than adequate and is usually specified. Experience with practical transformers has shown that an overload of six times the continuous rating can be applied for this time. The relevant rating is, however, based on the maximum output current and the maximum e.m.f. which the transformer can produce; the necessary continuous rating is therefore:

$$\frac{2.2 \times 18}{6} = 6.6 \text{ kVA}$$

This value may be rounded up to a standard size, so that a rating of 10 kVA may be specified.

An alternative rating of 5 kVA would correspond to an overload factor of 8 times and a time rating of 15 seconds.

The continuous loading may be due to third harmonic current flowing through the neutral earthing system and the machine and connections capacitance. The impedance of the latter is normally equal to that of the earthing resistor at fundamental frequency; at triple frequency it will be much less, and therefore negligible in its effect on the total impedance. Also, earth faults drawing less than the relay setting current of 5% will not be cleared and hence may exist for an extended period.

Total loading at relay setting of 5%

$$= 0.05^2 \times 1.7 \times 8000$$

$$= 34 \text{ watts}$$

This value is much less than the continuous rating and is therefore negligible. The residual harmonic current may be greater than this but will not normally be important.

### Transformer secondary rating

The rated secondary voltage may have any value and should be chosen to give a suitable secondary current. In the example quoted above, a secondary knee-point voltage of 250 volts, making the ratio 18,000/250 volts, will give a maximum secondary current at normal generator voltage of  $(18,000/250) \times 1.7$ , that is, 122 A.

### Loading resistor

The equivalent resistor is equal to the earth fault capacitance of 4680 ohms. The secondary circuit resistance is therefore:

$$4680 \times \left[ \frac{250}{18,000} \right]^2 = 0.9 \text{ ohms}$$

This is the total resistance required; the total transformer winding resistance, expressed in terms of the secondary circuit, should be deducted to obtain the value of the loading resistor.

A standard 10 kVA transformer can be expected to have a copper loss of about 310 watts at 75°C. In terms of a 250 volts secondary winding, the transformer resistance will be:

$$R_T = \frac{W}{I_s^2} = \frac{310}{40^2} = 0.194 \text{ ohms}$$

The loading resistor should therefore have a resistance of 0.706 ohms and be rated to carry:

$$1.3 \times 1.7 \times \frac{18,000}{250} = 159 \text{ amperes for 30 seconds}$$

### Transformer reactance

The leakage reactance will probably not exceed 4% based on the continuous rating; the actual value will be specified by the manufacturer. In terms of the secondary circuit this value will be:

$$X = \frac{250^2}{10^4} \times 0.04 = 0.25 \text{ ohms}$$

Hence the  $X/R$  ratio is  $0.25/0.9$ , that is, 0.28. It is considered that the  $X/R$  ratio should not exceed 2. The above value is therefore satisfactory. The effect of reactance is to reduce the actual fault current by partial compensation of the capacitive component, but it will not reduce the neutral current by more than a few per cent, which can generally be ignored.

### Current transformer rating for protection

The earthing transformer secondary current for a generator terminal fault at normal voltage is 122 amperes. A current transformer ratio of 100/1 will be satisfactory. The current can never exceed 160 A and larger values need not be considered.

Alternatively, a voltage relay type VDG14 is connected across the loading resistor; see Section 17.9.2.

An alternative method of earthing a generator-transformer unit is to earth it through a resistance of about 40 ohms, which will pass a current which may be 5% or less of the generator rating, for example, rating 100 MVA, 13.8 kV, 4180 A; earthing resistor 40 ohms, maximum earth fault current 200 A.

## 17.3

### PHASE FAULTS

Phase-phase faults clear of earth are less common; they may occur on the end portion of stator coils or in the slots if the winding involves two coil sides in the same slot.

In the latter case the fault will involve earth in a very short time. Phase fault current is not controlled by the method of earthing the neutral point.

## 17.4

### INTERTURN FAULTS

Interturn faults are also uncommon, but not unknown. They are not covered by conventional protection systems and the extra complication of the methods available for dealing with them is often thought not to be justified by the risk. In this case an interturn fault must develop into an earth fault before it can be cleared.

Apart from burning the core, the greatest danger arising from failure to deal quickly with any fault is fire. A large portion of the insulating material is inflammable, and in the case of an air-cooled machine, the forced ventilation can quickly cause flame arising from an arc to spread around the winding. Fire will not occur, however, in a hydrogen-cooled machine, provided the stator system remains sealed.

## 17.5

### WINDING PROTECTION

The most satisfactory method of protecting an alternator stator is the Merz-Price circulating current technique. Both longitudinal and transverse systems are used.

### 17.5.1

#### Longitudinal differential protection of direct connected generators

The circulating current principle is discussed fully in Section 10.4, which should be referred to for the theory of the system.

It is usual to provide phase and earth fault protection as shown in Figure 17.2(a). Protection for earth faults only can be arranged as in Figure 17.2(b). This arrangement is likely to be used only when the individual phases are not brought out at the neutral end.

The relay voltage setting is decided from the secondary lead drop. The minimum primary operating current is calculated by adding the sum of the exciting losses of all the parallel-connected current transformers at the relay setting voltage to the relay minimum operating current and multiplying by the current transformer turns ratio.

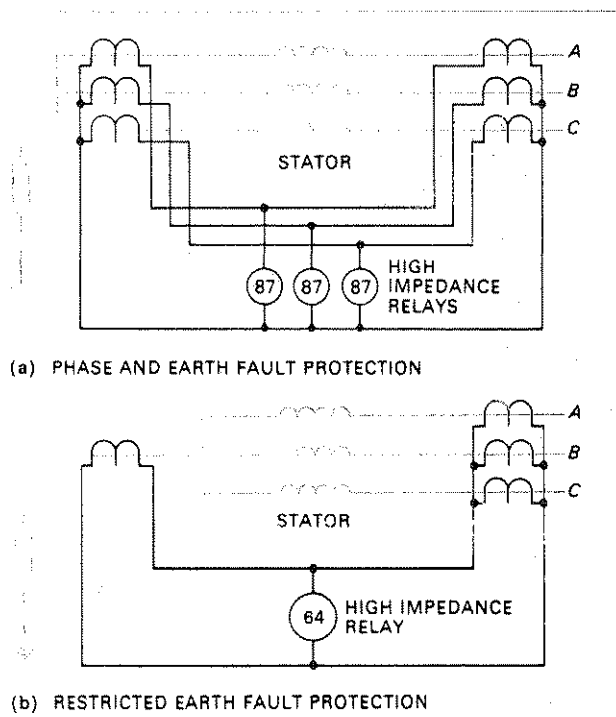


Figure 17.2 Stator differential protection.

Having determined the minimum primary operating current, it is a simple matter to calculate the minimum earth fault voltage which will produce this current, bearing in mind the value of the earthing resistance. This, expressed on the basis of the phase voltage, gives the per unit minimum distance from the neutral point at which a fault must be placed to cause relay operation, and the winding above this point is the range of winding which is protected. It will be seen that virtually the whole winding is protected against interphase faults, since no limiting impedance is included in the fault circuit.

A longitudinal differential system does not protect against interturn faults.

High impedance relays are designed in line with the theory given in Section 10.4. Types CAG34 and FAC34 are high speed attracted armature relays having the high impedance required by the above theory. The type CAG34 relay comprises a tuned armature relay fed from a tapped auto-transformer, a stabilizing resistor being connected in series.

The type FAC34 is designed as a voltage calibrated relay. Tuned elements are connected to multi-tapped resistors, giving a range of voltage settings of 25–175 volts in steps of 25 volts. The relays are applied in line with the theory of limited spill voltage described in Section 10.4

Relay consumption is 0.02–0.025 A. It is desirable, however, to shunt each complete relay and stabilizing resistor

by a non-linear Metrosil resistor in order to limit the amount of overvoltage that might occur during an in-zone operating condition. The Metrosil has a very small effect on the total relay consumption unless very high values of stabilizing resistance are used.

As an alternative to the simple high impedance relay, a biased system can be used. Actually, a combination of bias and stabilizing resistance is most effective, giving a system which can be stable regardless of the through current magnitude. The value of stabilizing resistance required is relatively low, so the minimum relay operating voltage is also low. Since relay settings are based on lead resistance, the use of bias is of most value if the leads are exceptionally long, and results in less onerous current transformer design requirements.

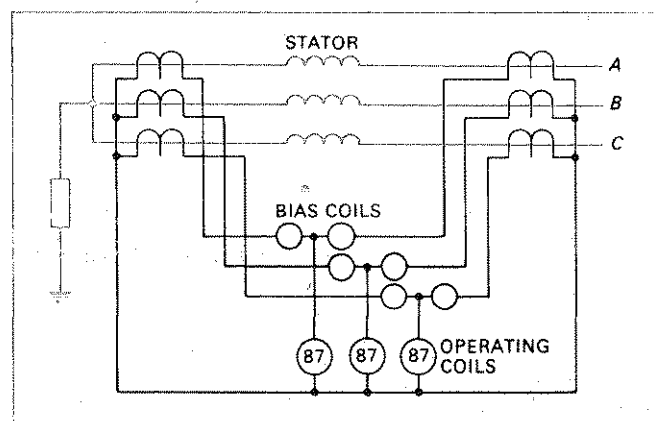


Figure 17.3 Biased differential protection.

An example is the type DDG relay, which is of the induction pattern, each pole having two electromagnets producing opposed torques on a common disc. One magnet carries the operating coil and the other a pair of bias coils, the combination being connected as shown in Figure 17.3.

A typical bias characteristic is shown in Figure 17.4. It will be noted that both the minimum setting and the bias slope are low, thereby ensuring high fault sensitivity. The impedance of the operating coil is normally sufficient, no extra stabilizing resistance being needed to ensure complete stability.

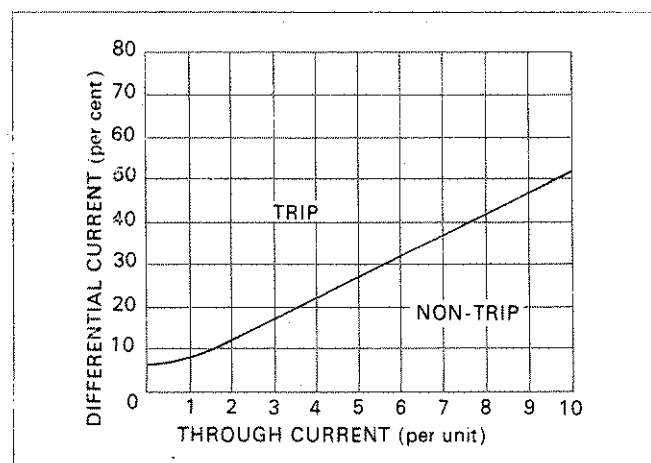


Figure 17.4 Typical bias characteristic of percentage differential relay.

### 17.5.2

#### Longitudinal differential protection of generator-transformers

The generator stator and transformer can be protected as a single zone; the current transformers are located in the generator neutral connections and in the transformer secondary cables. The current transformers should be rated

according to conditions (a) and (b) in Section 16.7.1. The transformer will probably have some tap variation; it is usual to apply a through current biased relay as in Section 16.7.1, condition (c).

The conditions due to the magnetizing inrush effect differ from those of a system transformer. Voltage is never applied suddenly to the transformer by switching; the transformer remains connected to the generator and is energized gradually as the latter is run up to speed and excited. It would appear, therefore, that no magnetizing transient phenomenon can occur.

However, magnetizing inrush currents may flow in the transformer for the following reasons:

a. The voltage applied to the transformer will be depressed by an external close-up short circuit and will recover when the fault is cleared. A certain amount of transient will occur at the instant of voltage recovery; the following conditions are relevant.

If the transformer is replaced by the equivalent 'tee' circuit it will be seen that the exciting impedance is separated from the short circuit by the secondary leakage reactance. Assuming typical values of generator and transformer impedances, the voltage across the exciting impedance, and hence the transformer flux, will be reduced to only about 20% of normal. Moreover, this flux will be in the correct direction, as opposed to reverse direction residual flux in the worst case discussed in Section 16.3. So even with 100% voltage recovery the transient flux could not exceed 1.8 times normal value as compared with 2.8 times normal for a switched transformer.

Interruption of fault current normally occurs at a current zero which corresponds to a voltage maximum, as the system is mainly reactive. Voltage recovery at this instant gives no exciting current transient. Some current chopping can take place, particularly with air blast circuit breakers, but this is unlikely to take place if the current is more than 20% of the peak value, that is, at more than  $10^{\circ}$ – $12^{\circ}$  from the zero point of the current wave. This suggests that the first flux swing will not exceed the normal peak value by more than 20%. This swing starts from a small negative value, perhaps 0.04 times the normal peak flux. The inrush current corresponding to this swing is likely to be quite small.

b. A large system transformer switched on to the station busbars will draw a high level of inrush current, supplied by the generator-transformer units. The current will flow through the differential zone and in principle should result

in a stable current balance condition. The offset nature of the current will cause saturation of the current transformers, but, provided the differential system has been correctly designed for through stability, no trouble should occur.

For this reason harmonic restraint has not been considered essential for the differential protection of a generator-transformer. This has been the basis of successful protective systems widely applied over many years.

Transformer differential protection, however, has been developed to give a fast and sensitive system, and it is now normal practice to apply this system to generator-transformers as well. The foregoing discussion has been included so that the various factors are understood.

## 17.6

### INTERTURN FAULT PROTECTION OF THE STATOR WINDING

The longitudinal differential system discussed in Section 17.5.1 does not detect interturn faults which remain clear of earth. This will be clear if Kirchoff's principle, that the currents flowing into and out of a matrix must balance regardless of any internal flow which takes place, is remembered.

Interturn faults have commonly been disregarded on the basis that if they occur they will quickly develop into earth faults. This is probably true if the fault is in the slot portion but will take a little longer in the region of the end connection. An approach of this kind is never attractive and may be entirely unjustified; there is a possibility of the machine being very seriously damaged before the fault evolves to a condition that can be detected by the longitudinal system.

#### 17.6.1

##### Transverse differential protection

Sometimes it is convenient for a generator stator to be wound with two identical three-phase windings connected in parallel. Provided the windings are brought out separately, it is possible to use a system of protection consisting of a balanced current arrangement between current transformers connected in the line ends of the two windings. In this case a biased system should always be used, as it is not possible to guarantee in advance that exact current sharing between the windings will take place; a small error in this sharing would produce instabil-

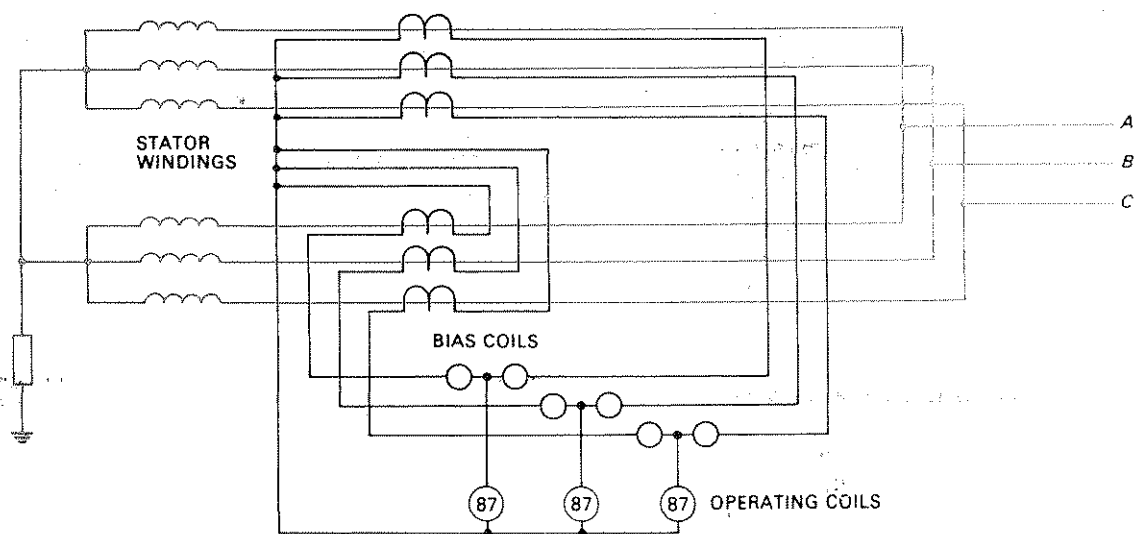


Figure 17.5 Transverse differential protection for double wound generators.

ity in an unbiased system at high levels of through fault current.

The scheme is shown in Figure 17.5.

Balanced current in the two windings produces a circulation of current in the current transformer secondary circuit, but any in-zone fault, including an interturn fault, will result in a circulation of current between the windings, producing an output in the relay operating circuit.

### 17.6.2

#### Interturn protection by zero sequence voltage measurement

Interturn faults in a generator with a single winding can be detected by observing the zero sequence voltage across the machine. Normally, no zero sequence voltage should exist but a short circuit of one or more turns on one phase will cause the generated e.m.f. to contain such a component.

External earth faults will also produce a zero sequence voltage on a directly connected generator. Most of the voltage will be expended on the earthing resistor, the drop on the generator being small and the zero sequence component being limited to one or two per cent. It is preferable, therefore, to measure the drop across the winding, rather than the zero sequence voltage to earth at the line terminals. This is done by a voltage transformer connected to the line terminals, with the neutral point of the primary winding connected to the generator neutral, above the earthing resistor. The arrangement is shown in Figure 17.6.

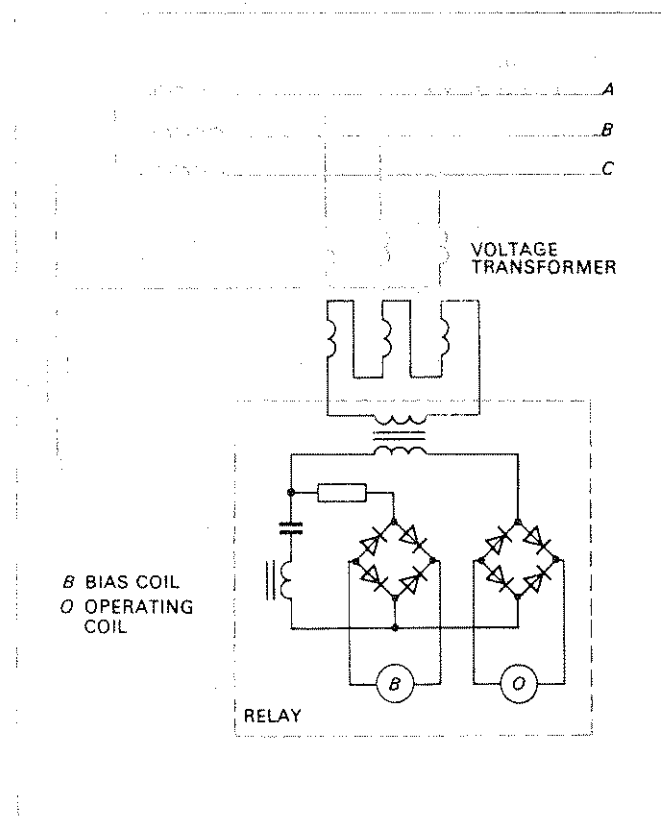


Figure 17.6 Interturn protection by zero sequence voltage measurement.

The voltage transformer has a broken-delta connected secondary winding that energizes a relay which therefore receives a quantity proportional to the zero sequence component only.

The third harmonic component of the e.m.f. is of zero sequence, and likely to be of a magnitude exceeding the required relay setting. It is therefore necessary to provide a filter to extract the third harmonic component from the VT output and apply it as a relay bias.

With a direct-connected machine it is still possible that a close-up earth fault will produce a zero sequence voltage drop greater than that produced by the short-circuiting of one turn. It is therefore necessary to apply a short time delay to the tripping outlet.

An external earth fault cannot draw zero sequence current through the generator of a generator-transformer unit and hence will produce no residual voltage from the voltage transformer. No time delay is required in this case.

### 17.7

#### OVERLOAD PROTECTION

A generator operating on a large system under continuous supervision is not in much danger of accidental overloading. The power that can be generated is limited by the steam production and hence cannot rise unnoticed or be maintained for any appreciable period above the programmed level.

Overloads in terms of current or MVA as distinct from megawatts are possible. Depending on the voltage regulator setting and type of control relative to the rest of the system, a given generator may take a disproportionate share of the MVA load on the system.

It is not usual to provide overload protection for supervised machines. It is desirable to provide an overload relay having a suitable time characteristic to an unsupervised hydro-generator which is otherwise equipped with fully automatic control.

Large machines are usually provided with thermocouples or resistance thermometer elements embedded in the stator winding, whereby the temperature of the winding can be measured during service, using suitable millivoltmeter or potentiometer instruments. A single instrument is used with a multi-way selector switch to check the temperature indications from a number of embedded elements distributed through the winding.

The rotor temperature is checked by measuring the resistance of the field winding. Both a high temperature alarm relay and a winding temperature indicating instrument can be used in conjunction. These are energized by the voltage across the field winding and by the excitation current, using a 100 millivolt shunt, the one shunt being common to both devices.

### 17.8

#### OVERCURRENT PROTECTION

It is usual to apply overcurrent relays of the I.D.M.T. pattern to generators, as a general protection 'back-up' feature. These relays are not in any way related to the thermal characteristics of the generator and are intended to operate only under fault conditions.

In the case of a single generator feeding an isolated system, overcurrent relays should be energized by current transformers at the neutral end of the machine, in order to respond to winding fault conditions. Relay settings should be chosen taking into account the decrement characteristics of the generator including the performance of the voltage regulator. If this is not done correctly, there is a danger, under certain fault conditions, for example a three-phase terminal short circuit, that the initial high fault current will decay to a value below the relay current setting before the relay completes its full contact travel. The relay then makes a partial operating motion and resets without fulfilling its function. The settings chosen must be the best compromise between assured operation in the foregoing circumstances and discrimination with the system protection.

In the more usual case of a generator which operates in parallel with others and forms part of an extensive interconnected system, the difficulty of arriving at a satisfactory compromise becomes acute. The practice therefore is

changed to energize overcurrent relays from current transformers at the line end of the machine. Settings are chosen which will ensure discrimination and usually prevent operation for external faults. Operation for stator winding faults is due to current fed back from the system. This current is supplied by many generators in parallel and, being stabilized by the system impedance, is not subject to as much decrement as it is in the case of the single machine.

Typical settings for an I.D.M.T. relay with a standard characteristic are:

Current setting 150%

Time multiplier setting 0.6

It can be seen that this practice provides no back-up protection at all for the system or even for the station busbars.

If the system protection consists entirely of high speed types it may be possible to vary the foregoing practice by lowering the current and time settings to values which will ensure operation with uncleared busbar or close-up feeder faults. If this is attempted, an ample discriminating margin should be allowed over the estimated operating time of all adjacent feeder protections under the most unfavourable conditions of current distribution. The calculation should generally be made for the maximum value of fault current for the assumed conditions; current decrement will usually increase the discriminating margin.

### 17.8.1

#### Voltage controlled overcurrent protection

The grading difficulties discussed above arise largely because of the variable response of the generator to differing degrees of excitation or voltage regulation, the latter possibly including a field forcing technique with the object of maintaining the system voltage under fault conditions.

A scheme to resolve this problem is provided by a voltage controlled overcurrent relay type CDV22. This has two time/current characteristics which are selected by a voltage measuring relay energized by the system voltage. During overloads, when the system voltage is sustained near normal, the relay operates on a long inverse time characteristic. Under close-up fault conditions, the busbar voltage will fall and the voltage relay will select the other characteristic, which is similar to that of a standard I.D.M.T. relay. For intermediate conditions caused by more remote faults, the degree to which the voltage will be sustained depends on the response of the voltage regulator. The fault current will vary to the same extent and the voltage relay will select the appropriate characteristic.

The type CDV22 relay is similar to a type CDG overcurrent relay, but with wound shading coils. A voltage element contained in the same case has a contact which short-circuits the shading coils when the voltage is low but picks up to insert a resistance in their circuit when the voltage is high.

For direct-connected solidly earthed generators the voltage relay is connected phase to neutral and the characteristic changes when the voltage falls to 60% of the rated value. In other cases the relay measures line voltage and switches at 30%. Typical characteristics are shown in Figure 9.10.

### 17.8.2

#### Voltage restrained overcurrent protection

An alternative technique is applied in the type CDV21 voltage restrained relay. The elements of this relay each comprise two induction electromagnets arranged to provide opposed torques in a single disc rotor. One electromagnet has a 'current' winding very similar to that of a standard I.D.M.T. relay; the other has an equivalent 'voltage' winding and is energized from a VT connected to the generator. The effect is to provide an I.D.M.T. type of overcurrent relay, the characteristic of which is modified continuously according to the voltage at the machine terminals. Alternatively, the relay may be regarded as an im-

pedance type with a long dependent time delay. In consequence, for a given fault condition the relay continues to operate more or less independently of current decrement in the machine. A typical characteristic is shown in Figure 9.11.

## 17.9

### STATOR EARTH FAULT PROTECTION

The stator protection can usefully be supplemented by an earth fault system in addition to the overcurrent relay. For a direct-connected machine, an earth fault relay is energized by a current transformer in the neutral point earthing lead. Such a system is unrestricted and must be graded with feeder protection. The relay will therefore have an inverse time characteristic.

The generator-transformer presents a different problem, in that the generator and transformer primary winding constitute an electrically isolated system which cannot interchange zero sequence current with the transmission network; for this reason, no grading problem exists.

### 17.9.1

#### High resistance earthing

A current transformer mounted on the neutral/earth conductor can energize an instantaneous relay with a setting of 10% of the maximum earth fault current, as shown in Figure 17.7(a).

This is the lowest setting that is considered to be safe from spurious operations due to transient surge currents transmitted from the EHV system through the inter-winding capacitance of the power transformer.

A time delayed relay is more secure in this respect, and may have a setting as low as 5%. Since the generating units under consideration are usually large it is considered to be

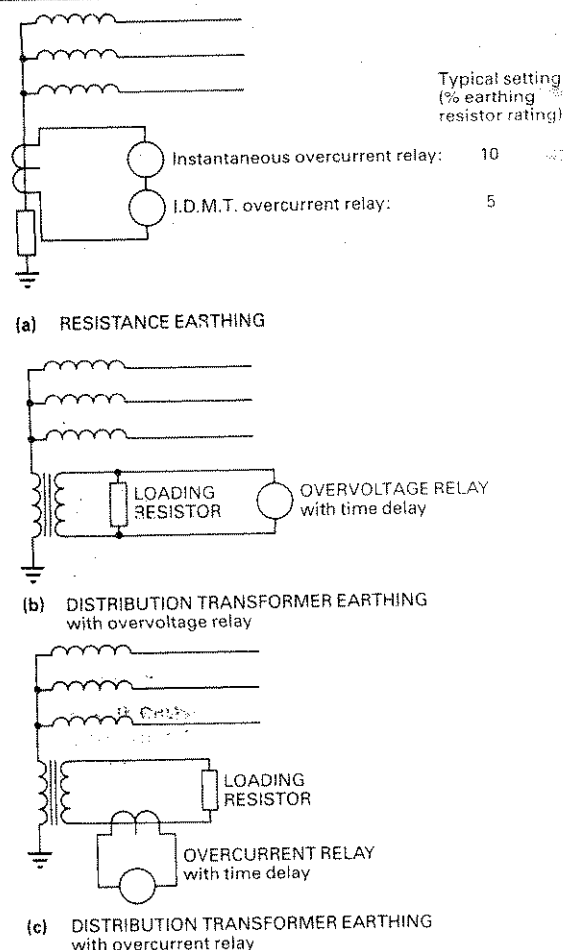


Figure 17.7 Earth fault protection of generator stator winding.

worthwhile to apply both an instantaneous and a time delayed relay with settings of 10% and 5% respectively; this is the optimum compromise in performance.

### 17.9.2

#### Distribution transformer earthing

In this arrangement, shown in Figure 17.7(b), the secondary winding of the earthing transformer is usually designed for medium voltage, which permits relays to be directly connected. A voltage relay connected across the secondary winding with its loading resistance can be used to detect earth faults, since only during these is the transformer energized. However, the earthing system is designed for a low current, nominally corresponding to the maximum zero sequence charging current, and not greatly different from possible values of third harmonic current. In order that the relay may have a satisfactorily low setting, it is necessary for it to be insensitive to current of the third harmonic frequency.

The type VDG 14 relay is so compensated. The relay is of the induction disc pattern, and the coil circuit is tuned to the system frequency by a series-connected reactor and capacitor. These components are energized from a tapped auto-transformer which provides the adjustment of the relay voltage setting. At voltages above the setting the reactor saturates and detunes the circuit giving the relay a high continuous voltage rating.

Tuned wound shading coils are fitted so that the relay develops maximum torque at the system frequency and is much less sensitive at the third harmonic frequency.

A setting range of 5.4–20 volts is provided; the third harmonic minimum operation level is at least 20 times higher.

Normally a setting is chosen which will give protection to 95% of the winding.

The relay is time delayed to avoid operation being caused by transmitted surges. High speed operation is unnecessary, as the fault current is limited to a low value. A time multiplier setting of 0.3–0.4, corresponding to operation in 1.5–2.0 seconds at 10 times the voltage setting, will be adequate for most applications.

Alternatively, a current-type relay energized from a current transformer connected in the resistor circuit can be used. The relay should have a setting which, taken in conjunction with the current transformer ratio, will give an overall setting of 5% of the maximum earth fault current at rated generator voltage. This relay also should incorporate a third harmonic filter. A suitable relay, type CDG11, with a harmonic filter will give the required performance when used with a current transformer with a secondary rating of 1A and a primary winding rating equal to or slightly less than the resistor current with a generator terminal earth fault. See Figure 17.7(c).

### 17.9.3

#### Earth fault protection for the complete stator winding

Earth fault protection schemes described in the foregoing Sections are relatively simple and have been well proven over many years. In applications where the earthing resistor value has been chosen to limit the maximum earth fault current to a level well below the full load current of the generator, these relays carry the principal responsibility for protecting against earth faults, as the effective setting of the overall differential protection may be of the same order as the maximum fault current through the earthing resistor.

However, at best these simple schemes protect only 95% of the stator winding measured from the generator output terminals, leaving 5% at the neutral end unprotected. For large machines there is an increasing requirement for detection of earth faults occurring anywhere in the stator winding including this neutral end zone. This can be achieved by a low frequency injection scheme or by a protective system which monitors the third harmonic and fundamental components of the voltage at the generator neutral with respect to the earth potential.

#### i. Low frequency injection scheme

In this scheme a sub-harmonic voltage is applied via an injection transformer connected in series with the neutral earthing impedance. A relay which monitors the sub-harmonic current is arranged to operate when the current increases due to an earth fault on the stator. This type of scheme provides effective coverage of the complete stator winding. However the cost of implementation tends to be high due to the cost of injection equipment.

#### ii. Third harmonic voltage schemes

An alternative method of covering earth faults at the neutral end of the stator winding is to utilize the third harmonic voltage produced by non-linearities within the generator. Under healthy conditions, this voltage causes circulation of third harmonic capacitive charging currents resulting in a third harmonic voltage appearing between the neutral of the generator and ground. The value of voltage will depend on the relative values of the impedance of the earthing device, the capacitance to earth of the stator windings and the capacitance to earth of the buswork, cabling and transformer windings connected to the generator.

When a fault occurs close to the neutral of the generator, the third harmonic voltage between neutral and ground will reduce to a near-zero value. On high resistance earthed generators, measurement of this voltage provides a clear discrimination between faults in the neutral region of the stator winding and healthy conditions. This gives a basis of

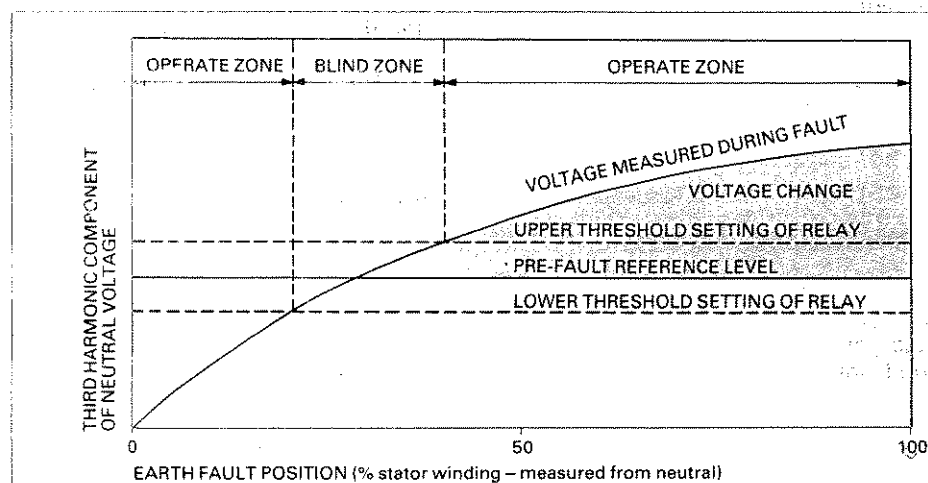


Figure 17.9 Typical changes in third harmonic levels measured at the generator neutral for earth faults on the stator.

measurement to overcome the dead zone of the simpler schemes detailed in Sections 7.9.1 and 7.9.2.

For fault positions further away from the neutral the reduction in third harmonic voltage measured at the neutral will be progressively less, until a point is reached, typically 20% to 30% along the winding from the neutral, for which the pre-fault and post-fault levels are identical. For fault positions beyond this null point the third harmonic component measured at the neutral will increase. See Figure 17.8.

Predicting the exact levels of third harmonic voltage on an actual machine is difficult as it varies both with the design and more importantly with the power output of the machine to be protected. This makes the selection of a suitable setting for a fixed threshold relay to discriminate between all pre-fault and post-fault conditions virtually impossible without severe loss of protection coverage.

A method of overcoming this is for the relay to measure the levels of third harmonic neutral voltage existing for a healthy machine, and to set thresholds automatically above and below this 'learnt' level to define relay operation, as shown in Figure 17.8. The magnitude of the level of third harmonic at any instant can be compared with the 'learnt' thresholds and the trip output energized when the magnitude goes outside the upper or lower thresholds. In this way, the third harmonic relay will cover all earth faults in the stator winding apart from those in the blind zone corresponding to voltages between threshold settings. See Figures 17.8 and 17.9.

Another method using third harmonic voltages to detect earth faults occurring in the neutral end zone involves the measurement of third harmonic voltages at the neutral and at the terminals of the generator. The ratio of these voltages will change under earth fault conditions and this can be used as a basis for relay operation.

Monitoring the fundamental component of neutral voltage in the conventional way described earlier results in an operating zone (see Figure 17.9) which complements a relay operating on the harmonic principle.

When combined together to form a protective system, each relay element covers the blind zone of the other and the system will detect earth faults anywhere on the stator winding.

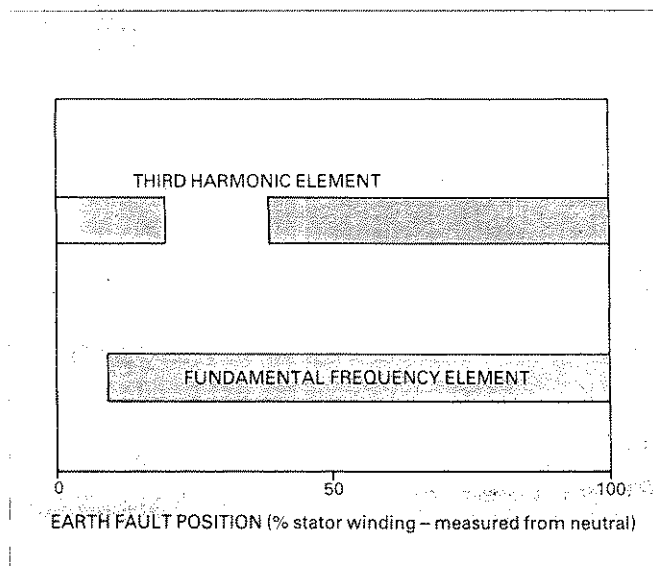


Figure 17.9 Typical relative operation zones of complementary stator earth fault relay elements.

## 17.10 OVERVOLTAGE PROTECTION

Overvoltage can refer either to a high speed transient or to a sustained condition at system frequency.

### 17.10.1 Transient overvoltage

Surge voltages originate largely in the transmission system because of switching and atmospheric disturbances. According to the degree of risk, such surges are dealt with by co-ordinating gaps shunting the EHV terminals to earth, or surge diverters connected to incoming lines or station busbars. Sometimes surge diverters are connected also to the generator terminals; the need for installation at this point largely depends on the relative capacitance of the generator to transformer interconnections compared with the inter-winding capacitance of the transformer.

### 17.10.2 Power frequency overvoltage

Overvoltages should not occur on a machine fitted with a voltage regulator. Overvoltage may be caused by the following contingencies:

- Defective operation of the voltage regulator.
- Operation under manual control with the voltage regulator out of service. A sudden variation of the load, in particular the VAR component, will give rise to a substantial change in voltage because of the large voltage regulation inherent in a typical alternator.
- Sudden loss of load (due to line tripping) may cause a hydro set to overspeed, because of the relatively slow operation of the governor and turbine gates. The speed is inherently limited to a value which can be withstood (for example 180% of normal speed) but may cause a dangerous voltage rise.

Overvoltage protection is not usually applied to attended machines but may be required for unattended automatic hydro-stations. Where applied, it is most effective to use an instantaneous relay with a high setting; settings up to 150% are used.

## 17.11 UNBALANCED LOADING

A three-phase balanced load produces a reaction field which, to a first approximation, is constant and rotates synchronously with the rotor field system.

Any unbalanced condition can be resolved into positive, negative and zero sequence components.

The positive sequence component is similar to the normal balanced load.

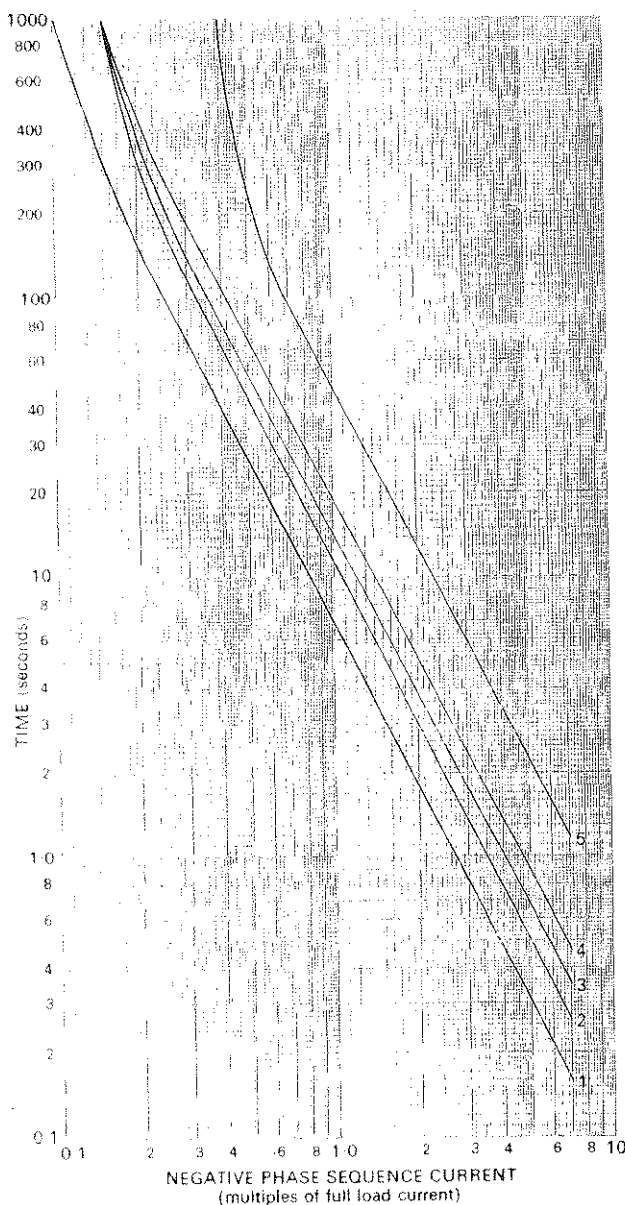
The zero sequence component produces no main armature reaction.

The negative sequence component is similar to the positive sequence system, except that the resulting reaction field rotates counter to the d.c. field system and hence produces a flux which cuts the rotor at twice the rotational velocity, thereby inducing double frequency currents in the field system and in the rotor body. The resulting eddy-currents are very large and cause severe heating of the rotor. So severe is this effect that a single-phase load equal to the normal three-phase rated current can quickly heat the brass rotor slot wedges to the softening point; they may then be extruded under centrifugal force until they stand above the rotor surface, when it is possible that they may strike the stator iron. Concentration of heating occurs on portions of the coil binding rings and here surface fusion has been known to occur.

Since the heating depends on the reaction field and hence also on the load current, a machine can be assigned a continuous negative sequence rating. For turbo-sets this rating is low; standard values of 10% and 15% of the continuous mean rating (that is, positive sequence) have been adopted. Rather surprisingly, the lower rating applies when the more intensive cooling techniques are applied, for example hydrogen-cooling with gas ducts in the rotor to facilitate direct cooling of the winding. This anomaly



occurs because the better cooling enables a greater Maximum Continuous Rating (MCR) to be obtained from a machine of given size. This term is defined\* as a 'statement of the load and conditions assigned to the machine by the manufacturer at which the machine may be operated for an unlimited period whilst complying with the standard requirements'.



| Type of machine              | Type and cooling and cooling medium       | Curve number | Continuous $I_2^2 t$ rating % F.L.C. | $I_2^2 t$ value |
|------------------------------|-------------------------------------------|--------------|--------------------------------------|-----------------|
| Turbo-alternator             | Direct hydrogen 30 lb / sq"               | 1            | 10                                   | 7               |
| Turbo-alternator             | Conventional hydrogen 30 lb / sq"         | 2            | 15                                   | 12              |
| Turbo-alternator             | Conventional hydrogen 15 lb / sq"         | 3            | 15                                   | 15              |
| Turbo-alternator             | Conventional air or hydrogen 0.5 lb / sq" | 4            | 15                                   | 20              |
| Typical salient pole machine | Conventional air                          | 5            | 40                                   | 60              |

Figure 17.10 Typical negative phase sequence current withstand of generators with different forms of cooling.

Short time heating is of interest during system fault conditions; the heat dissipation during such periods is negligible and the heat generated can be considered to be retained entirely within the thermal capacity of the rotor. Using this approximation it is possible to express the heating by the law:

$$I_2^2 t = K$$

where  $I_2$  = negative sequence component (per unit of MCR)

$t$  = time (seconds)

$K$  = constant proportional to the thermal capacity of the generator rotor.

For heating over a period of more than a few seconds it is necessary to allow for the heat dissipated; from a combination of the continuous and short time ratings the overall heating characteristic can be deduced to be:

$$M = \frac{I_2}{I_{2R}} = \sqrt{\frac{1}{1 - e^{-(I_{2R}^2 t)/K}}}$$

where  $I_{2R}$  = negative phase sequence continuous rating per unit MCR

The heating characteristics of various designs of generator are shown in Figure 17.10.

The negative sequence rating of a salient pole generator as normally used in a hydro-station is usually much greater than that of a cylindrical rotor machine, but depends on the efficiency of the amortisseur winding. The performance of a typical hydro-generator is shown as curve 5 in Figure 17.10.

#### 17.11.1

##### Negative sequence protection

The negative sequence component can be detected by the use of a filter network. Many circuits for this purpose have been evolved, one of which is shown in Figure 17.11.

The A phase CT is loaded with a resistor, whereas the C phase CT energizes a reactor and resistor in series. the total impedance of which is equal to that of the A phase resistor, and the power factor of which is 0.5. The C phase voltage drop, therefore, leads the current by 60°. With positive sequence currents, the A and C phase voltages are in opposition and so sum to zero, whereas negative sequence currents result in the condition shown in the vector diagram Figure 17.11(c), and produce a substantial combined voltage between the points X and Y in Figure 17.11(a). A relay connected to these points will therefore respond only to the negative sequence component.

If the current contained a zero sequence component, this would also produce an output. Zero sequence current does not cause heating of the generator rotor, so this component is sometimes eliminated from the measurement, either by the use of delta-connected current transformers or by a balancing arrangement in the network. This is not necessary for a generator-transformer unit since no zero sequence current can flow in the generator because of external system conditions.

Since the source of unbalance is in the system and will affect all generators in the vicinity, these should not be disconnected unless the condition remains uncorrected for such a time that there is danger of the generators being damaged. The protection should have a time delay characteristic which is as near as is practicable to the heating characteristic of the machine, thereby providing as much time as possible for the operation staff to locate and isolate the fault before a total shut-down becomes necessary. Full advantage will not be taken of the time so provided unless the operator is warned at an early stage; the protection should therefore contain an alarm feature which operates at a setting equal to or slightly lower than that of the

\* BS 4999 Part 1: 1972



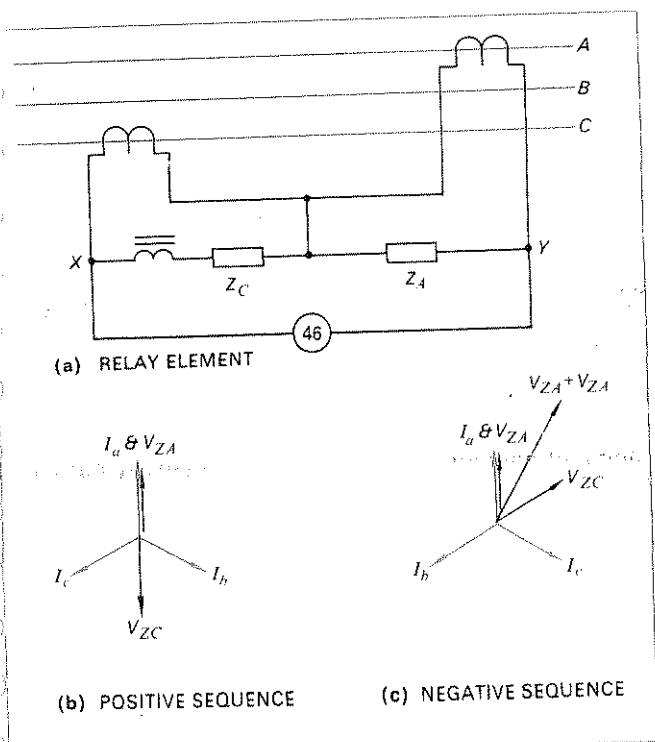


Figure 17.11 Negative sequence network.

tripping element, and is delayed by only a few seconds, to avoid unnecessary alarms being given for system faults that are cleared quickly in the usual way.

The circuit of an electromechanical relay for this service is given in Figure 17.12.

In this relay, auxiliary transformers in the relay carry polyphase primary windings with turns arranged to cancel any zero sequence component. These transformers energize two networks; the first, associated with a long time delayed induction element, is the tripping unit. The second network energizes a sensitive armature-type element which provides an alarm. A definite time delay relay should be interposed in the alarm system.

The time/current characteristic of the tripping function is shown in Figure 17.13.

The type CTN is a modern negative sequence relay using electronic techniques; see Figure 17.14.

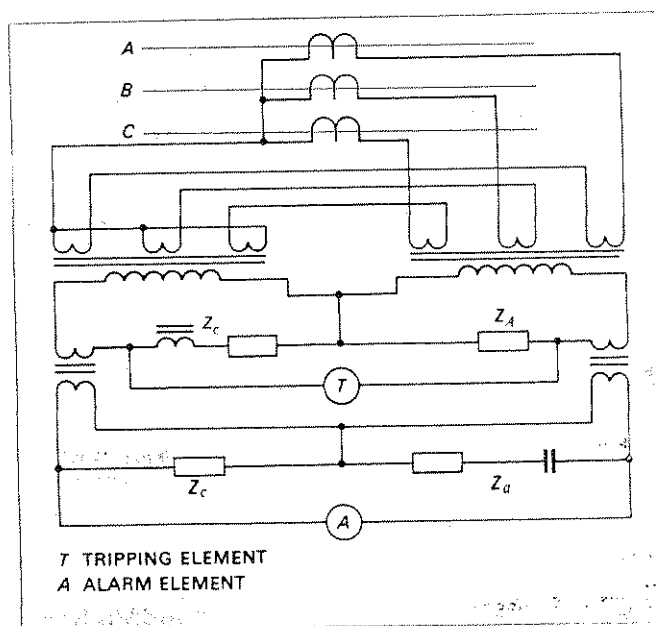


Figure 17.12 Typical electromechanical negative phase sequence relay.

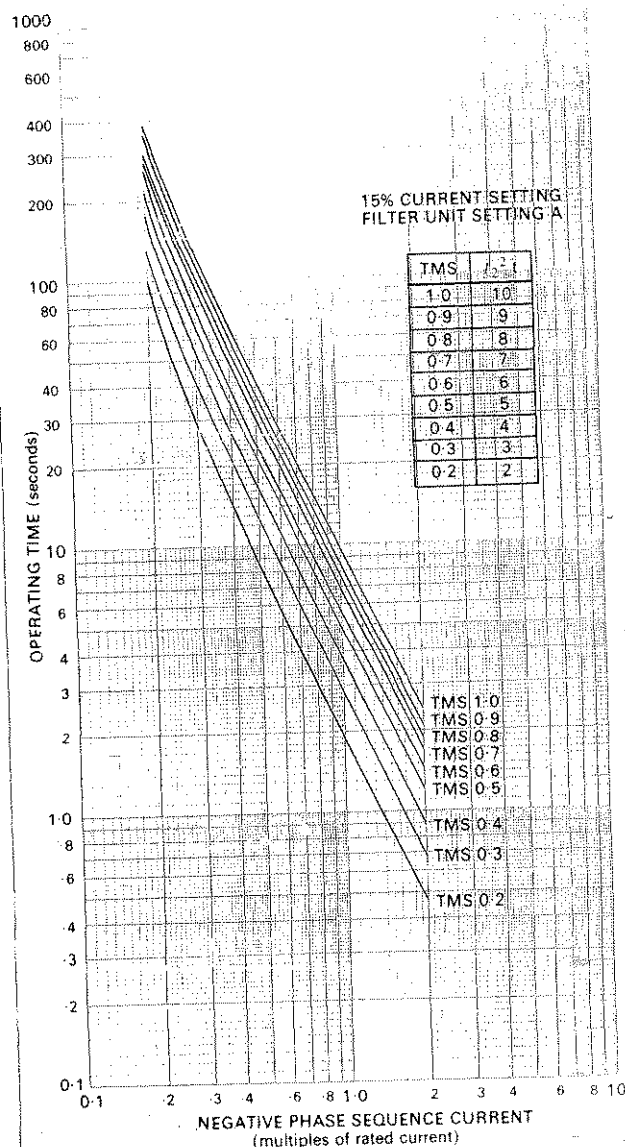


Figure 17.13 Time/current characteristic of typical electromechanical negative phase sequence relay.

Any zero sequence component is first removed by a star/delta group of auxiliary transformers contained within the relay; these transformers are also provided with primary taps to give a range of settings to match typical generator negative sequence ratings. The settings provided are 7.5%, 10%, 15%, 20% and 30% of MCR. The secondary currents are fed to a network which in this case includes resistive and capacitive impedances, the principle of 60° shift of one vector being maintained. An output proportional to the square of the negative sequence current is derived by connecting the sequence network to a 'shaping' circuit comprising resistors and zener diodes which acts as a non-linear potentiometer and is designed to produce the square law relationship. This process is followed by integrating and level sensing circuits, the final stage energizing a hinged armature relay to provide the tripping contacts.

The overall response characteristic obtained is shown in Figure 17.15.

A separate channel provides the alarm facility, with a fixed time delay of five seconds and a current setting adjustable between 70–100% of the tripping setting.

## 17.12

The field circuit of a generator, comprising the winding and the armature of the exciter with any associated field circuit

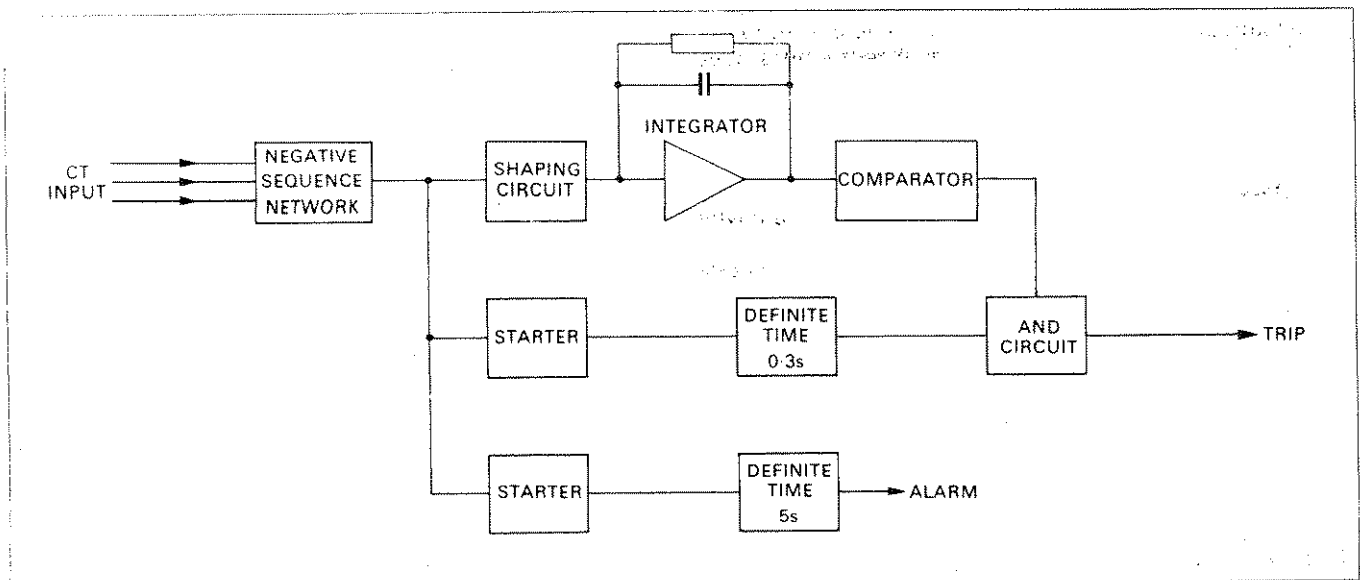


Figure 17.14 Static negative sequence relay type CTN.

breaker, is an isolated d.c. circuit which in itself need not be earthed. This means that if an earth fault occurs, no fault current will flow and the need for action will not be evident. Machines have, in fact, been operated in this condition for considerable periods.

Danger arises if a second earth fault occurs at a separate point in the winding, causing the current to be diverted, in part at least, from the intervening turns. The field current of a large machine is considerable and, when so diverted, can burn the conductor, causing serious damage very rapidly.

Still more damage may be caused mechanically. If a large portion of the winding is short-circuited the flux may adopt

a pattern such as that shown in Figure 17.16. The attracting force at the surface of the rotor is given by:

$$F = \frac{B^2 A}{8\pi}$$

where  $A$  = area and  $B$  = flux density

It will be seen from Figure 17.16 that the flux is concentrated on one pole but widely dispersed over the other and intervening surfaces. The attracting force is in consequence large on one pole but very weak on the opposite one, while flux on the quadrature axis will produce a balancing force on this axis. The result is an unbalanced force which in a large machine may be of the order of 50–100 tons. This force is rotating with the rotor and hence produces a violent vibration which may damage bearing surfaces or even displace the rotor by an amount sufficient to cause it to foul the stator.

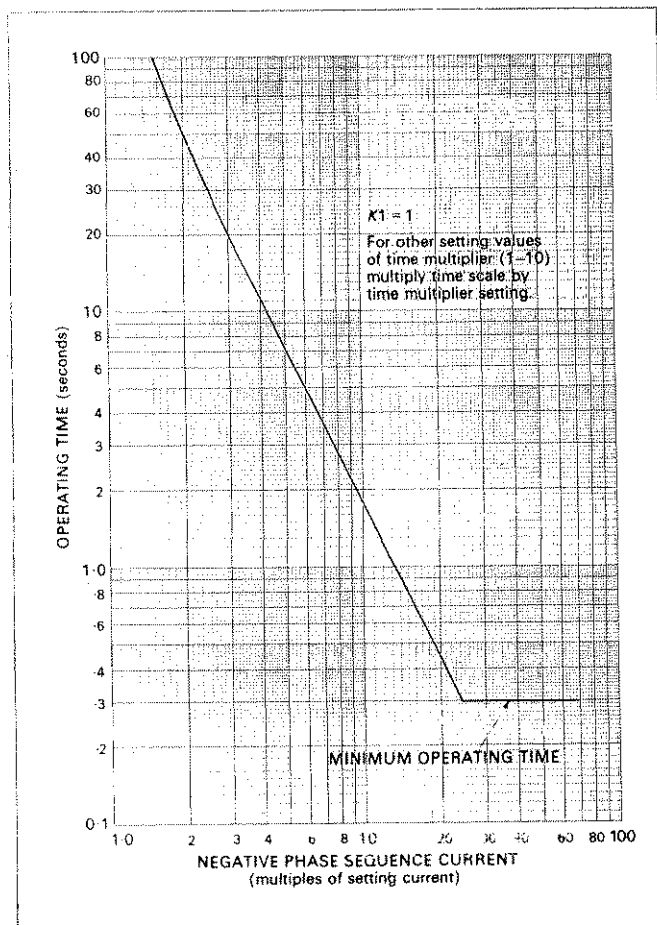


Figure 17.15 Time/current characteristic of static negative phase sequence relay type CTN.

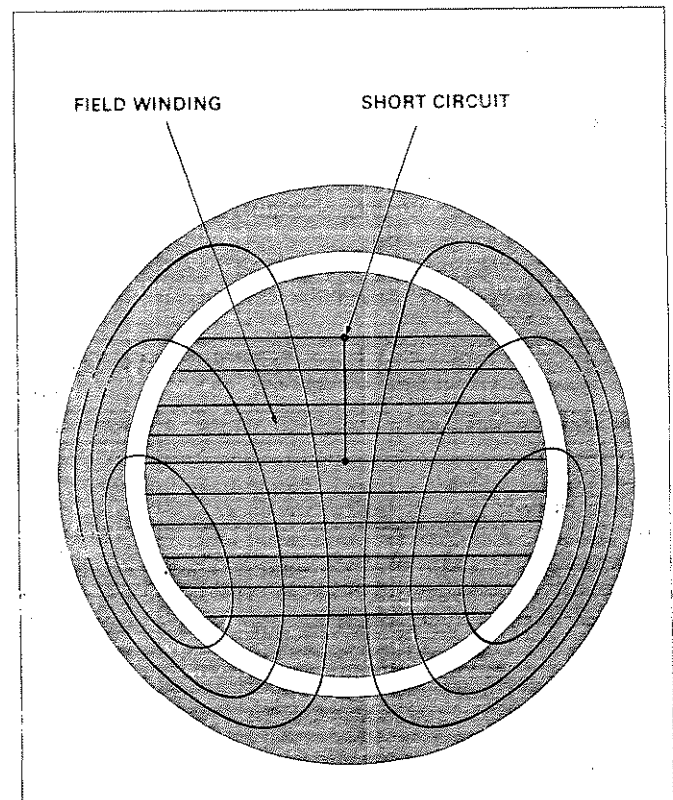


Figure 17.16 Flux distribution on rotor with partial winding short circuit.

### 17.12.1

#### Rotor earth fault protection

Three methods are available to detect this type of fault:

- Potentiometer method.
- A.c. injection method.
- D.c. injection method.

##### Potentiometer method

This scheme, which is shown in Figure 17.17, comprises a centre tapped resistor connected in parallel with the main field winding. The centre point of the resistor is connected to earth through a voltage relay. An earth fault on the field winding will produce a voltage across the relay, the maximum voltage occurring for faults at the ends of the winding.

A 'blind spot' exists at the centre of the field winding, this point being at a potential equal to that of the tapping point on the potentiometer. To avoid a fault at this location remaining undetected, the tapping point on the potentiometer is varied by a pushbutton or switch. It is essential that station instructions be issued to make certain that the blind spot is checked at least once per shift.

This scheme is simple in that no auxiliary supply is needed. A type VMG relay with a setting of 5% of the exciter voltage is adequate. The potentiometer will dissipate about 60 watts.

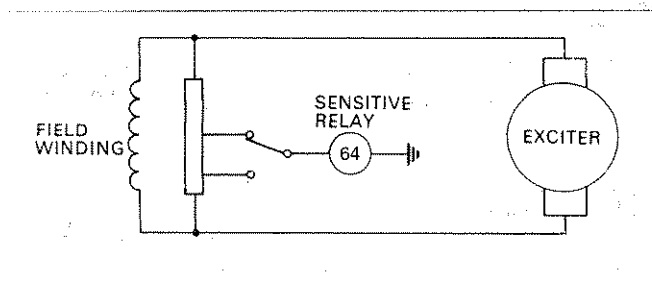


Figure 17.17 Earth fault protection of field circuit by potentiometer method.

##### A.c. injection method

This scheme is shown in Figure 17.18. It comprises an auxiliary supply transformer, the secondary of which is connected between earth and one side of the field circuit, through an interposed capacitor and a relay coil. The field circuit is subjected to an alternating potential at substantially the same level throughout, so that an earth fault anywhere in the field system will give rise to a current which is detected by the relay. The capacitor limits the

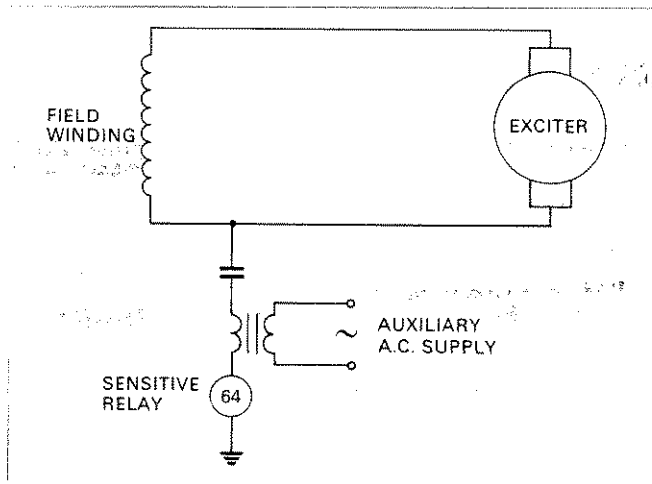


Figure 17.18 Earth fault protection of field circuit by a.c. injection

magnitude of the current and blocks the normal field voltage, preventing the discharge of a large direct current through the transformer.

This scheme has an advantage over the potentiometer method in that there is no blind spot in the supervision of the field system. It has the disadvantage that some current will flow to earth continuously through the capacitance of the field winding. This current may flow through the machine bearings, causing erosion of the bearing surface. Nevertheless, it is common practice to insulate the bearings and to provide an earthing brush for the shaft, and if this is done the capacitance current should be harmless.

##### D.c. injection method

The capacitance currents associated with a.c. injection may be avoided by rectifying the injection voltage, as shown in Figure 17.19. The d.c. output of a transformer-rectifier power unit is arranged to bias the positive side of the field circuit to a negative voltage relative to earth. The negative side of the field system is at a greater negative voltage to earth, so an earth fault at any point in the field winding will cause current to flow through the power unit. The current is limited by including a high resistance in the circuit and a sensitive relay is used to detect the current.

The fault current varies with fault position, but this is not detrimental provided the relay can detect the minimum fault current and withstand the maximum.

The relay must have enough resistance to limit the fault current to a harmless value and be sufficiently sensitive to respond to a fault which, at the low injection voltage, may have a fairly high resistance. The relay must not be so sensitive as to operate with the normal insulation leakage current, taking account of the high voltage to earth at the negative end of the winding and any overvoltages due to field forcing and so on.

The type VME relay uses a sensitive balanced armature polarized element. It is designed in two models for field systems of up to 450 and 1200 volts respectively. Injection voltages of 24 and 50 volts are provided by the self-contained power unit.

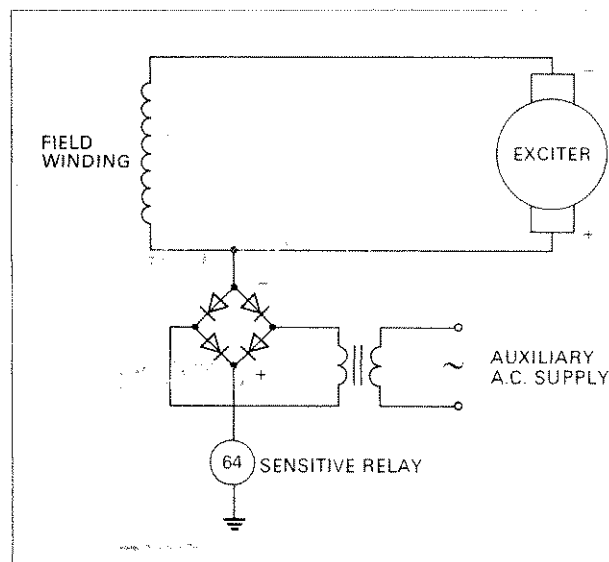


Figure 17.19 Earth fault protection of field circuit by d.c. injection

The relay for a 450 volt field system will operate with a fault at the positive end of the winding of up to 10,000 ohms resistance, and will remain stable with a distributed leakage equivalent to a total insulation resistance of 300,000 ohms.

Comparable values apply to other field voltages and to the alternative relay.

This consideration has assumed a single value for  $X_G$ . Actually, the reactance  $X_q$  on the quadrature axis differs, the ratio of  $X_d/X_q$  being known as the saliency factor. This factor varies with the slip speed. The effect of this factor during asynchronous operation is to cause  $X_G$  to vary at slip speed. In consequence, the loss of field impedance locus does not come to a single point, but continues to describe a small orbit about a mean point.

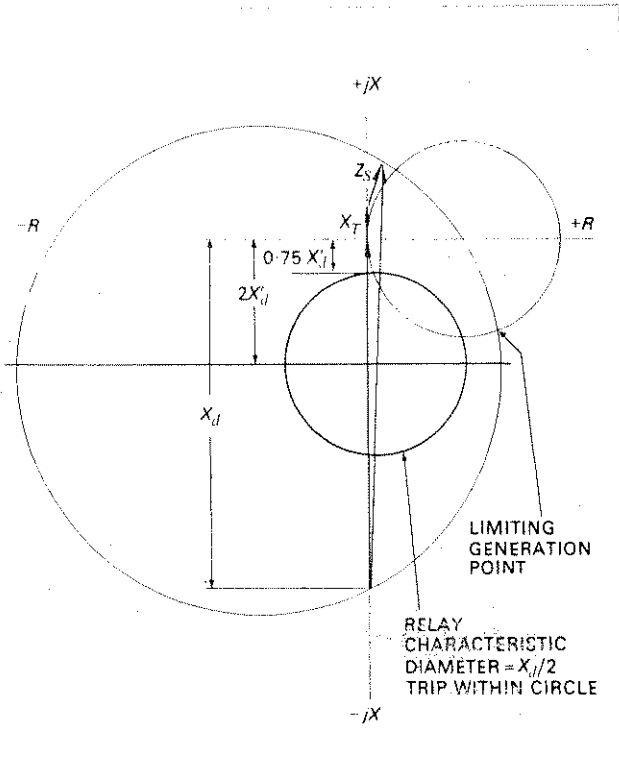


Figure 17.23 Locus of limiting operating conditions of synchronous machine.

A protection scheme for loss of synchronism must operate decisively for this condition, but its characteristic must not inhibit stable operation of the generator.

One limit of operation corresponds to the maximum practicable rotor angle, taken as  $120^\circ$ . The locus of operation can be represented as a circle on the impedance plane, as shown in Figure 17.23, stable operating conditions lying outside the circle.

On the same diagram can be drawn the locus of the full load of one per unit power. Part of this circle represents a condition that is not feasible, but the point of intersection with the maximum rotor angle curve can be taken as a limiting operating condition.

From a comparison with the phase swing curves of Figure 17.22, it will be seen that a relay with a characteristic that does not impose any limit on stable generator operation will not readily give assured operation for all out-of-step conditions.

A further consideration is that action different from that needed for dealing with pole slipping is necessary for asynchronous operation.

### 17.13.1

#### Protection against asynchronous operation

A mho type impedance relay, type YCGF, with a characteristic as shown in Figure 17.24, observes the change in impedance from the normal load value.

The relay characteristic should enclose as fully as possible the impedance orbit corresponding to that of the asynchronous condition; for normal slip values this will be an orbit surrounding the value  $2X'_d$ .

The characteristic should be clear of the pole swing loci and of the limiting operational point as described above.

The relay characteristic is centred on the negative reactance, and is usually offset by 50%–75% of  $X'_d$ . It is given a diameter of from 50–100% of the synchronous reactance  $X_d$ . With these settings the requirements are satisfied.

### 17.13.2

#### Protection against pole slipping

A system power shock may make a generator rotor oscillate, with consequent variations of current, voltage and power factor. The oscillations may disappear in a few seconds, in which case it is desirable that no tripping takes place. If, however, the angular displacement of the rotor exceeds the stable limit, the rotor will slip a pole pitch. If the disturbance has been sufficiently removed by the time this has occurred, the machine may regain synchronism, but if it does not, it must be isolated from the system.

Alternatively, the field switch may be tripped, reducing the condition to that of asynchronous running and thereby removing the violent power oscillations from the system and the corresponding severe mechanical torque oscillations from the machine. The load should then be reduced to a low value, at which the set will probably re-synchronize; if this does not work, reclosing the field switch with the excitation control set to the minimum position will cause the set to synchronize smoothly.

The range of possible positions of swing curves makes detection by a relay of the type used for asynchronous operation, however set, relatively uncertain. A better method is to use 'ohm' relays which have straight line characteristics on the impedance diagram. Two such relays are used, their respective characteristics being located on the left of and parallel to the total system impedance vector, as shown in Figure 17.24.

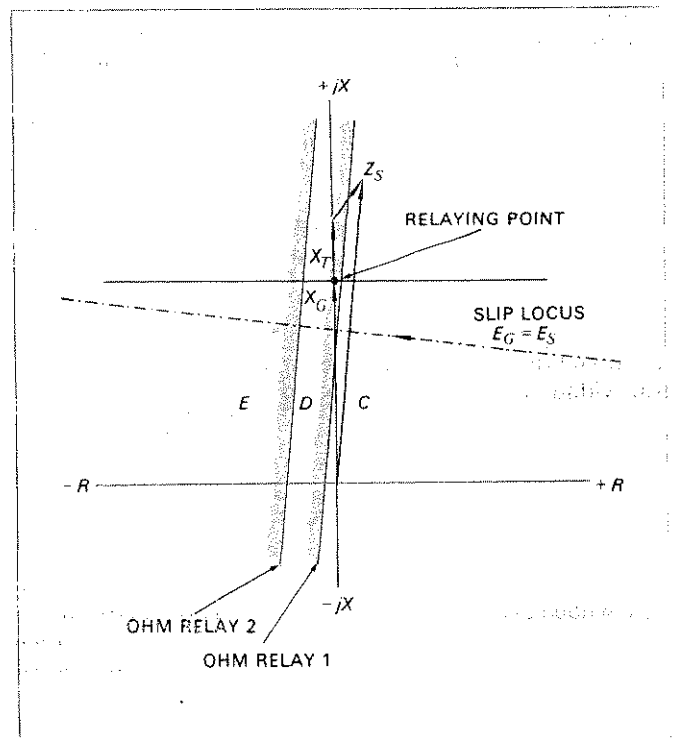


Figure 17.24 Pole slipping detection by ohm relays

These impedance relays have an operation area facing away from the direction of the first swing. The characteristics divide the diagram into three zones, C, D and E. As the impedance changes during a power swing, the extremity of the impedance vector moves along one of the power swing loci, traversing the three zones in turn, during which the relays operate in sequence.

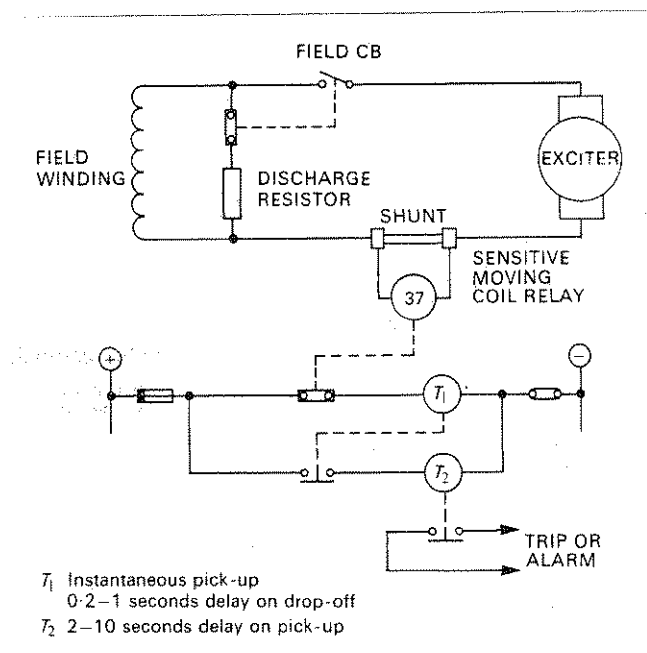


Figure 17.20 Loss of field protection using undercurrent relay.

time delayed on drop-off to stabilize the scheme against slip frequency effects.

Relay  $T_2$  operates either to trip or to give alarm of the condition. It is time delayed to prevent spurious operation for external faults.

This scheme is suitable for small machines, but not for large generators which may be required to operate with negligible excitation.

The quantity which changes most when a generator loses synchronism is the impedance measured at the stator terminals. On loss of field, the terminal voltage will begin to decrease and the current to increase, resulting in a decrease of impedance and also a change in power factor.

The generator and system can be depicted as shown in Figure 17.21.

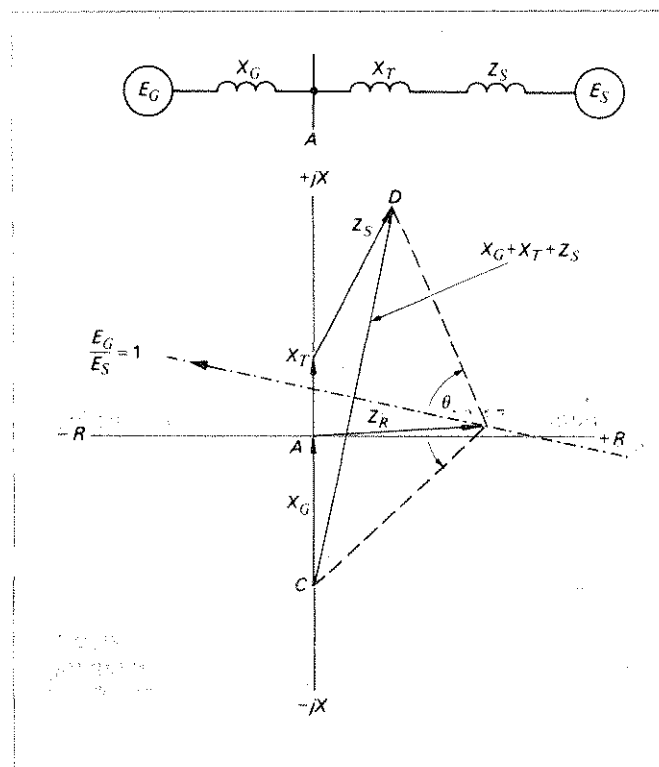


Figure 17.21 Basic interconnected system.

A relay to detect loss of synchronism will be located at point A; it can be shown that the impedance presented to the relay under loss of synchronism conditions (phase swinging or pole slipping) is given by:

$$Z_R = \frac{(X_G + X_T + Z_S)n(n - \cos \theta - j \sin \theta) - X_G}{(n - \cos \theta)^2 + \sin^2 \theta}$$

where  $n = E_G/E_S$  = ratio of generated to system voltage

$\theta$  = angle by which  $E_G$  leads  $E_S$  at any given time

If the generator and system voltages are equal the above expression becomes:

$$Z_R = \frac{(X_G + X_T + Z_S)(1 - j \cot \theta/2) - X_G}{2}$$

The general case can be represented by a system of circles with centres on the line CD; see Figure 17.22.

In the special case of  $E_G = E_S$  the circle is of infinite radius, that is a straight line which is the right bisector of CD.

Complete loss of excitation provides the special case of  $E_G = 0$ . Since  $n = 0$ ,  $Z_R = -X_G$ . The circle has now shrunk to a point at C.

When excitation is removed from a generator operating synchronously the flux dies away slowly, during which period the ratio of  $E_G/E_S$  is decreasing, and the rotor angle of the machine increasing. The operating condition plotted on an impedance diagram therefore travels along a locus which crosses the power swing circles and at the same time progresses in the direction of increasing rotor angle. After passing the anti-phase position, the locus bends round as the internal e.m.f. collapses, condensing on an impedance value equal to the machine reactance. The locus is illustrated in Figure 17.22.

The relay location is displaced from point C, one of the poles of the swing loci, by the generator reactance  $X_G$ . One problem in determining the position of these loci relative to the relay location is that the value of machine impedance varies with the rate of slip. At zero slip  $X_G$  is equal to  $X_d$ , the synchronous reactance, and at 100% slip  $X_G$  is equal to  $X_d''$ , the sub-transient reactance. The impedance in a typical case has been shown to be equal to  $X_d'$ , the transient reactance, at 50% slip, and to  $2X_d'$  with a slip of 0.33%. The slip likely to be experienced with asynchronous running is low, perhaps 1%, so that for the purpose of assessing the power swing locus it is sufficient to take the value  $X_G = 2X_d'$ .

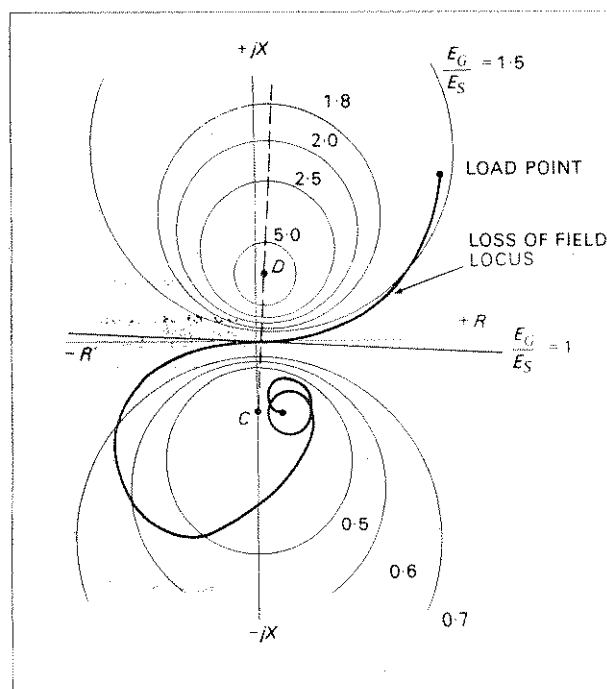


Figure 17.22 Swing curves and loss of synchronism locus.

phase current and A-C voltage will give a maximum torque response for a system power factor of unity. Other cyclic combinations of quantities will give equivalent results. A definite time element, adjustable to any delay between 2 and 10 seconds, is incorporated.

In special cases, such as hydraulic sets, where the motoring power available to operate the relay may be only 0.2%–2% of the rated power, a more sensitive relay is necessary; the type WCD11 polyphase relay, which has an operating setting of less than 0.5% at unity power factor, should be used. The reverse power relay WCD11 does not incorporate a time delay and a separate definite time delay relay, with an adjustable setting range of 2–10 seconds, should be used.

### 17.15.2 Overspeed

The speed of a turbo-generator set rises when the steam input is in excess of that required for the load. The speed governor can normally control the speed, and, in any case, a set running in parallel with others in an interconnected system cannot accelerate much independently even if synchronism is lost; see Section 17.13. However, if load is suddenly lost when the HV circuit breaker is tripped, the set will begin to accelerate. The speed governor is designed to prevent a dangerous speed rise even with a 100% load rejection, but nevertheless an additional centrifugal overspeed trip device is provided to trip the emergency steam valves if the overspeed exceeds 10%.

Despite the safety measures, a risk still remains if the steam

valves fail to close completely; even a very narrow residual opening can pass enough steam to cause overspeed with no load on the generator.

Protection associated with severe electrical faults is arranged to trip the high voltage circuit breaker, the field circuit breaker and the turbine steam valves simultaneously. This action is necessary to minimize consequential damage and has been assessed as presenting the least overall risk.

For less urgent protective trips, the risk of overspeeding is avoided by delaying disconnection from the system until the electrical output is reduced to about 1% of rating. Even if the steam input is not reduced any further, tripping this small load will not cause a dangerous speed rise.

A sensitive power relay is used to determine when the power output has fallen below this value or has reversed. The type WCD12 polyphase low power interlock relay is of the eight pole induction cup pattern with an internal a.c. operated auxiliary output element. The relay is set to have its contacts closed when not energized, the contacts being opened by the relay torque when the generator produces a power output.

The power relay contacts are connected to check the tripping contacts of all the protective systems for which a short delay can be tolerated, as shown in Figure 17.25. The relay is designed with normally closed contacts opened by forward current, instead of relying on reverse power to close them, in order that operation under motoring conditions may be as decisive as possible. It also ensures that the operation of protection will not be inhibited by a small

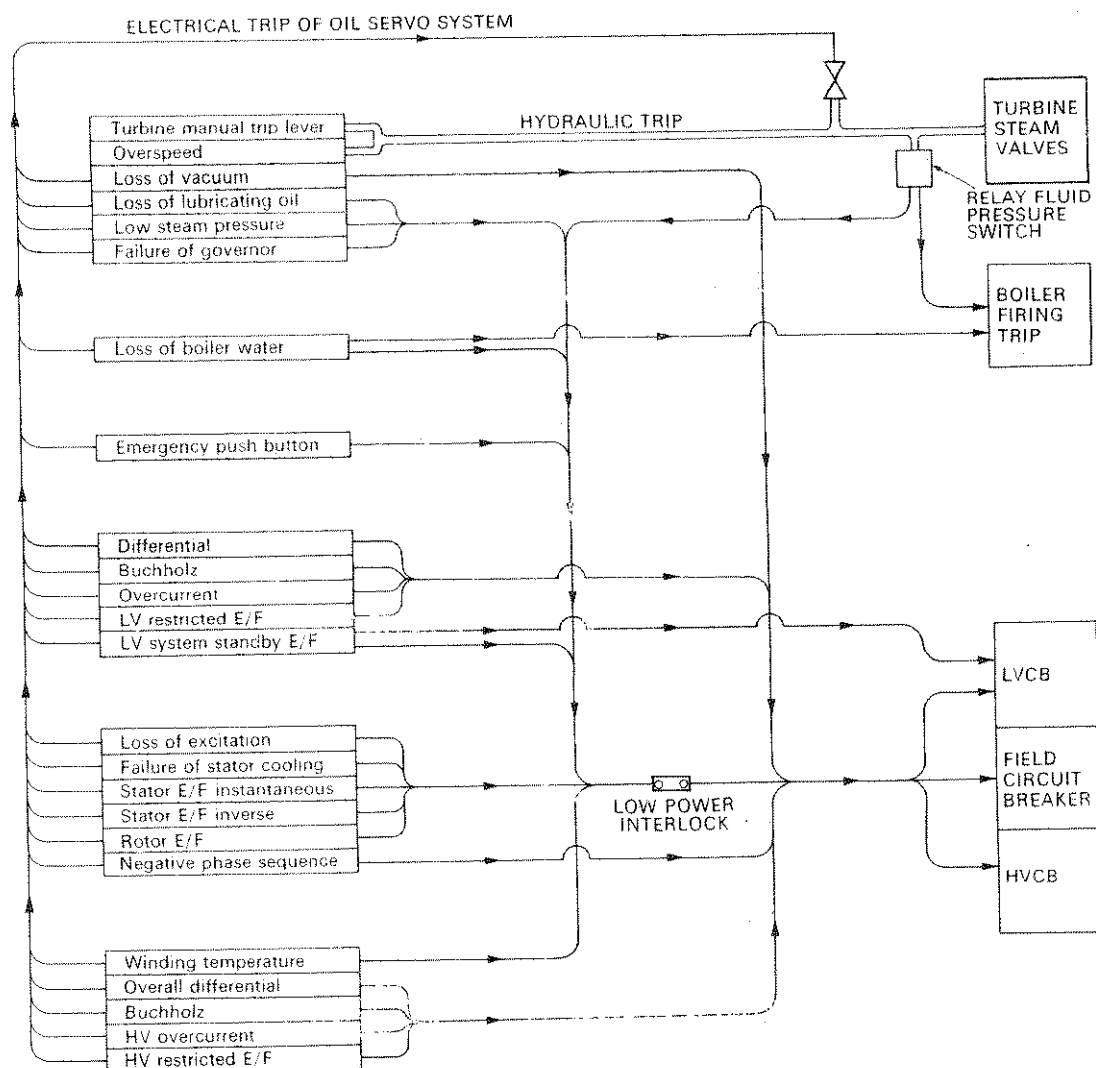


Figure 17.25 Typical tripping arrangements for generator-transformer unit.

steam leakage through the stop valves of an amount insufficient to produce a dangerous speed rise.

As a further guarantee of security, the power relay is usually duplicated, the contacts being connected in parallel.

When a less urgent trip takes place initiating closure of the steam valve, the generator rotor has to fall back from the load angle towards the no load position as the electrical output reduces. Some overswing is to be expected, and this will cause power oscillations sufficient to give a momentary false indication of motoring, although the steam conditions may not be safe for disconnection of the generator from the system. Even if the stop valve is safely closed, a little time is required for the high pressure steam in the steam chest, piping and the turbine itself to discharge. To cater for this further contingency, a definite time delay of two seconds is interposed.

When applied to large sets, the design requirements of this low power interlock scheme are very stringent because of the inherent sensitivity required. The relay must maintain a setting between 0.2% and 0.7% over a phase angle range of  $0^\circ$ – $89.5^\circ$  leading and lagging.

The associated current and voltage transformers must also have very low errors. In practice it is difficult to keep the separate errors within the required limits, and it is necessary to calibrate the relay and transformers together, having provided the relay with the means to compensate for the transformer errors.

### 17.15.3

#### Boiler protection

A boiler may overheat if:

- i. The water level falls because of an interruption of the feed water supply.
- ii. The steam demand ceases when the turbine steam valves are tripped. In this case the superheater or the reheater tubes will overheat.

Loss of boiler water is detected by a device which trips the boiler firing immediately and initiates shut down of the set.

A similar action is initiated by the valve relay fluid switch when the turbine valves are tripped.

Loss of boiler firing is detected by a fall in steam pressure. A pressure sensitive device operates on the governing system, in the event of a fall in pressure below 90% of normal, to unload the set and finally to trip the turbine valves and the main circuit breaker.

### 17.15.4

#### Loss of vacuum

A failure of the condenser vacuum results in heating, which produces strain in the condenser tubes and so on, and also a rise in temperature of the low pressure end of the turbine. Vacuum pressure devices initiate progressive unloading of

the set and, if eventually necessary, tripping of the turbine valves and high voltage circuit breaker. The set must not be allowed to motor in the event of loss of vacuum, as this would cause rapid overheating of the low pressure turbine blades.

### 17.15.5

#### Lubricating oil failure

In some sets the bearing oil is derived from the same pump that supplies the servo-system controlling the governing valves. These valves are arranged to close if the oil supply fails, so that separate action need not be taken.

In many modern units the valve control fluid is separate from the lubricating oil. An oil flow device is therefore needed to detect bearing oil failure and trip the unit.

### 17.15.6

#### Rotor distortion

The cooling rates after a shut down are different at the top and bottom of the turbine casing. This may distort the rotor, so, to minimize the effect, it is customary to turn the rotor slowly during the cooling period. Turbines are equipped with 'barring gear' for this purpose. In large sets the tendency is to use higher barring speeds which assist the circulation of air within the casing and thus help to equalize the temperature in transverse planes for the turbine as a whole.

The rotors of large turbines weigh several tons, and a 0.1 mm displacement of the centre of gravity of a rotor from its axis of rotation will produce a centrifugal force equal to its weight.

The rotor will tend to revolve about an axis through its centre of gravity; if the latter does not coincide with the geometric centre of the shaft at the bearings, relative transverse motion will take place and the shaft will appear to be eccentric.

Eccentric running is detected by a pair of electromagnets mounted rigidly on the bearing housing and opposed diametrically across the shaft, as shown in Figure 17.26. The magnets are connected into a bridge circuit energized by a high frequency signal.

If the shaft is running eccentrically, the air-gaps under the two magnets will vary at the shaft rotation frequency in a mutually opposed manner. A corresponding variation in the inductance takes place, causing an unbalance signal from the bridge. The signal is extracted from the carrier and is suitably amplified to energize display and recording instruments.

By similar techniques, the changes in blade clearances are observed in terms of the relative axial motions due to the expansion of the turbine rotor and casing. Vibration at pedestal bearings can be measured with similar detecting

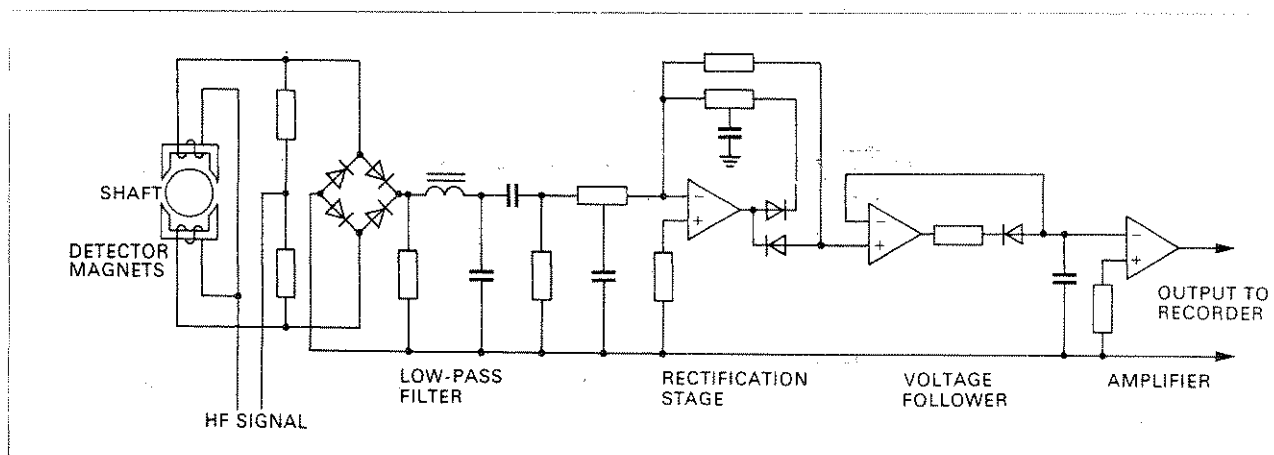


Figure 17.26 Detection of shaft eccentricity.



magnets and by observing motion relative to a mass of iron which is suspended from low rate springs. This mass 'floats' relatively motionless, thereby providing an absolute reference against which to measure the vibrating motion of the bearing.

## 17.16

### COMPLETE PROTECTION SCHEME

The techniques which are available to protect generating plant against the various faults and abnormal conditions which may occur have been discussed in the foregoing sections. In view of the range of possible protective systems it is necessary to realize that the design of a complete protective scheme will be governed by economic considerations.

With the largest machines, the total value of the plant is very great and protection against most contingencies should be considered. Its justification by a qualitative assessment of the risks is nevertheless always implied.

For these reasons, stator differential protection is universal, as also is stator earth fault protection for generator-transformers. Negative sequence protection is a necessity for turbo-type machines, and may be required for others. Rotor earth fault protection should always be applied.

Protection for loss of synchronism is needed for very large machines, but for generators of less than 50 MW whether it is applied or not will depend on the system characteristics.

Overheating detection is usually confined to indication or alarm systems for attended generators. In unattended stations a long time overcurrent relay or a scheme to measure the stator temperature may be considered.

Protection against the failure of the prime mover (motoring protection) will not normally be applied for main generating sets in attended stations. It may be necessary for engine driven sets and for others for which the risk of damage has been assessed as significant.

The various schemes to counter boiler, condenser and mechanical faults are normally applied in modern practice.

Smaller generators will not be so comprehensively protected. For ratings of 5 MVA or less, stator differential protection may take the form of a restricted scheme for earth faults only; the total saving is small but the change may be inevitable if the machine has only a single neutral end conductor brought out. Negative sequence protection will probably not be used unless any special risk is anticipated.

Rotor earth fault protection and field failure schemes will probably not be applied except under special circumstances at the upper end of this range.

As for mechanical system protection, in many cases motoring protection will be needed, the others being chosen according to the type of prime mover. Vibration and eccentricity protections are not likely to be required.

## 17.16.1

### Generator-transformers

The above general remarks apply to this class as well, but it should also be noted that:

- Differential protection covering the generator and transformer requires a design different from that for a generator only. The scheme will always have to be biased, and either harmonic bias or special attention to settings will also be needed.
- Earth fault protection will cover the generator and the transformer primary winding. It must be designed with the system of neutral earthing in mind.
- The remarks in (a) and (b) apply to all other forms of generator protection.
- In addition, the transformer will normally be provided

with restricted earth fault protection for the high voltage winding and Buchholz protection; see Chapter 16.

## 17.16.2

### Unit transformer protection

If a unit transformer is directly connected at generator voltage a number of special considerations apply.

The current taken by the unit transformer must be allowed for by arranging the differential protection as a three-ended scheme. Current transformers in the unit transformer leads are connected so that the current circulates with those in the generator neutral conductors.

Practice has varied in the past; the third set of current transformers has been placed on either the primary or secondary side of the transformer.

In the latter case the unit transformer is apparently located in the overall zone of protection; the protection so given to the unit transformer cannot, however, be considered to be adequate, since the relatively low rating of the latter and the corresponding high impedance will prevent the protection from operating for faults more than a little way from the primary terminals. Earth faults will in any case be limited by the generator neutral earthing impedance and will be detected only by the earth fault relays.

It may be concluded that there is little point in including this transformer in the overall scheme; in fact the main issue is that if it is included, the machine protection will trip for faults up to the transformer terminals. If the transformer is not included, such a fault could be out-of-zone while still leading to instability of the main scheme.

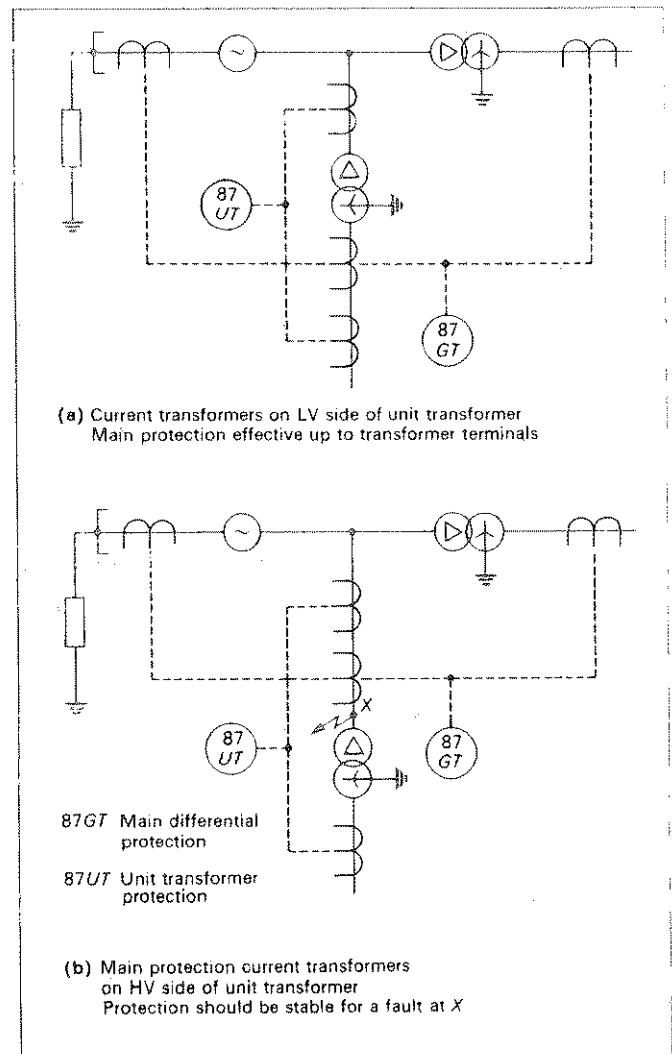


Figure 17.27 Overall differential protection with unit transformer.



Tripping will be necessary anyway, and an unstable operation might confuse the analysis and the determining of the location of the fault. The situation is illustrated in Figure 17.27.

## 17.17

### FIELD SUPPRESSION

The need to suppress as quickly as possible the field of a machine in which a fault has developed should be obvious, because as long as the excitation is maintained, the faulty generator, though isolated from the system, will continue to feed the fault and extend the damage. Removal of the motive power is no solution, because of the large kinetic energy of the machine.

The field cannot be destroyed immediately; the flux energy must be dissipated without causing an excessive inductive voltage rise in the field circuit. For machines of moderate size it is satisfactory to open the field circuit with an automatic air break circuit breaker without arc blow-out coils. Such a breaker permits only a moderate arc voltage, which is nevertheless high enough to suppress the field current fairly rapidly. The inductive energy is dissipated partly in the arc and partly in eddy-currents in the rotor core and damper windings.

With larger machines, that is, above about 5 MVA, it is better to provide a more definite means of absorbing the energy without incurring damage. This is done by connecting a 'field discharge resistor' in parallel with the rotor winding before opening the field circuit breaker. The resistor, which may have a resistance value of five times the rotor winding resistance, is connected by an auxiliary contact on the field circuit breaker; the breaker duty is thereby reduced to that of opening a low inductance circuit, and, after the breaker has opened, the field current flows through the discharge resistance and dies down harmlessly. The use of a fairly high value of discharge resistance reduces the field time constant to an acceptably low value, though it may still be more than one second.

### CALCULATION OF STABILIZING RESISTORS REQUIRED FOR INSTANTANEOUS TYPE CURRENT OPERATED RELAYS FOR ZONAL PROTECTION

eg:-

$$\text{Fault current} = 50,000 \text{ A} \quad I_r$$

$$\text{CT} = 2500/5 \text{ A} \quad N = 500$$

$$\text{Relay internal resistance} = 0.5 \text{ ohm} \quad R_0$$

$$\text{Max lead resistance of relay} = 0.1 \text{ ohm} \quad R_b$$

$$\text{Minimum current setting of relay} = 0.5 \text{ A}$$

$$\text{Relay pickup} = 3 \text{ V}$$

$$\text{VOLTAGE APPEARING ACROSS RELAY} = \frac{I_r}{N} (R_0 + R_b)$$

$$= \frac{50000}{500} (0.5 + 0.1)$$

$$= 60 \text{ V} \quad \left( \text{Relay will not operate at this voltage but stability is current through relay greater than expected value of } 0.5 \text{ A} \right)$$

$$Z\% \text{ of relay at current setting} = \frac{\text{Breaker}}{(I_{sc})^2} = \frac{3}{(0.5)^2} = 12 \text{ ohms}$$

∴ limiting current to the set value, the relay circuit impedance shall be minimum

$$\frac{60}{0.5} = 120$$

$$\therefore \text{additional resistance required} = 120 - 12 = 108 \text{ ohms}$$

# CURRENT TRANSFORMER KNEE POINT VOLTAGE KNEE POINT VOLTAGE

Definition: Point of magnetisation curve at which 10% increase in induced emf will give a 50% rise in excitation current.

Stability Voltage Setting =  $V'_S$

Kneepoint Voltage =  $V_K$

Excitation Current =  $I_e$

Relay Burden =  $V_D$

Actual Voltage Setting =  $V_{SA}$

CT secondary winding resistance =  $R_S$

Maximum loop lead resistance =  $R_P$

Relay setting current =  $I_r$

EFFECTIVE FAULT SETTING =  $I_S$   
Expressed in secondary amps.

R/S Secondary pilot current of } =  $I_f$   
max. fault current

$$\left[ \begin{array}{l} n = 3 \text{ for REF for 4 wdg (3 CTs)} \\ n = 4 \text{ for REF 7 wdg (4 CTs)} \\ n = 2 \text{ for m/c or TR diff protection} \end{array} \right]$$

$$V'_S \geq I_f (R_S + R_P)$$

$$V_{SA} = \frac{V_D}{I_r} + I_n R_{SM}$$

$$V_K \geq 2 V_{SD}$$

$$I_e = \frac{I_S \times I_n}{n}$$

eg. 5000/1 A  
250kV TR  
6.75% Z  
Stabilising Resistance  
GE relays 17.5 ohms for 0.5 A D.D. & 50 CT  
Secondaries.

## STABILISING RESISTANCE

$$R_{SM} = \frac{V'_S - \frac{V_D}{I_r}}{I_r}$$

# Intertripping

- 18.1
- 18.2

## 18.1

Intertripping, sometimes known as transferred tripping, is the controlled tripping of a circuit breaker so as to complete the isolation of a circuit or piece of apparatus in sympathy with the tripping of other circuit breakers.

This type of operation is needed for systems in which a fault does not give rise to enough fault current through any of the infeeds to the protected zone. Some examples of conditions for which intertripping is necessary are:

- a. A feeder with the principal power infeed at one end can receive only a very small infeed to a fault through the far end because of the relatively high impedance of the interconnections; see Figure 18.1(a).
- b. A fault in the transformer of a transformer-feeder may not draw an appreciable current through the feeder. In particular, a fault near the neutral point of a star winding may give rise to very little current through the terminals, and although detectable by locally situated transformer protection, it will not be seen from the remote end of the feeder. Core faults and other low energy fault conditions detected by a Buchholz relay will also remain undetected by the remote feeder protection; see Figure 18.1(b).
- c. A feeder supplying a load through a delta or an un-earthed star winding of a power transformer presents a particular problem if any power may be fed back from the receiving end. An earth fault on the feeder will not receive a contribution of zero sequence current from the receiving end because of the lack of a neutral/earth connection; any current that does flow may be less than the setting of overcurrent relays. When the sending end breaker trips, current will cease through the receiving end, except for capacitance currents, if the feeder remains energized by back-feed. Under this condition, if the fault is an arcing one, the fault arc may be continued, producing dangerous overvoltage surges. The problem can be dealt with by a neutral displacement scheme or by intertripping from the supply station to the receiving point LV breaker; see Figure 18.1(c).
- d. When current transformers are located on the feeder side only of a circuit breaker, as shown in Figure 18.1(d), a fault between the current transformers and the breaker will operate the bus protection although fault clearance depends on operation of the feeder protection; if this is of the unit type it will stabilize. Opening the adjacent circuit breaker will not clear the fault, and some form of intertripping to the remote feeder end breaker is necessary.

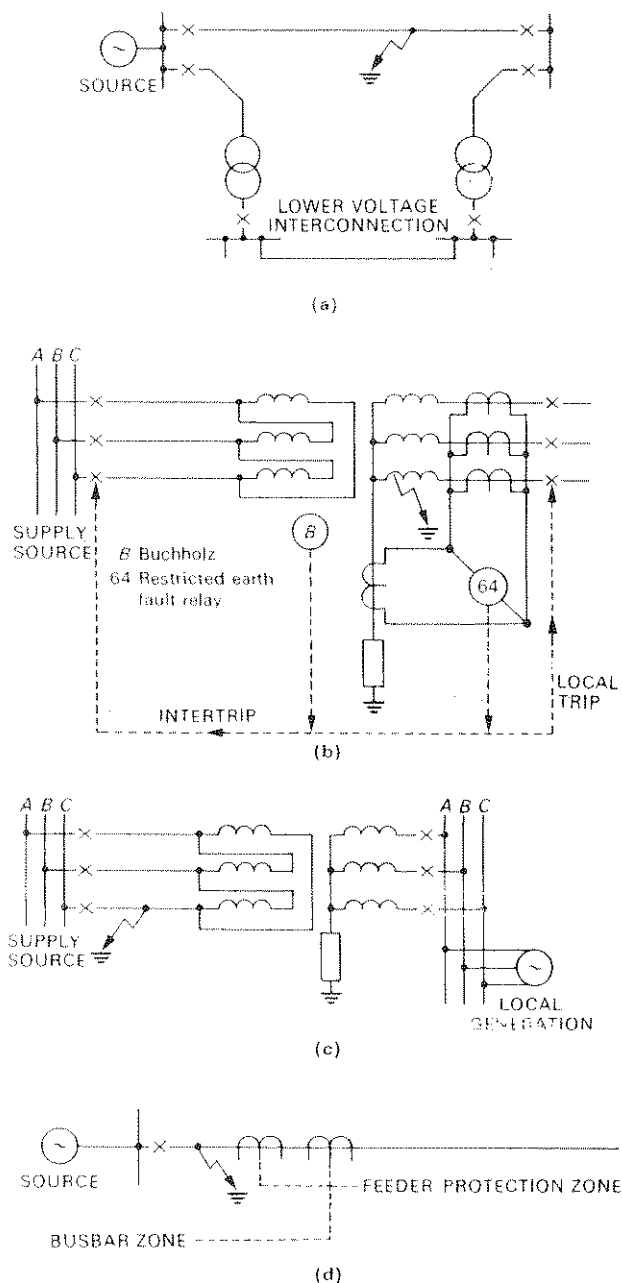


Figure 18.1 Typical system conditions requiring intertripping.

## 18.2

A wide range of intertripping techniques is available for the various circumstances that may arise, such as those just described.

The principal methods used are listed below:

- Direct d.c. signal on separate circuit.
- D.c. signal superimposed on unit protection system pilots.
- Voice frequency signal on pilot line.
- Carrier signal on power line.
- Interference with unit protection system.
- Fault throwing.

These methods are discussed in the following sections.

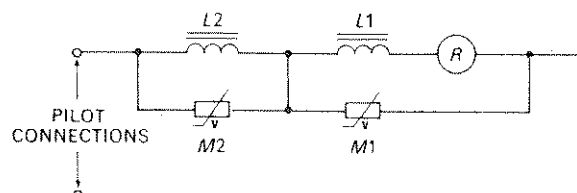
### 18.2.1

#### Intertripping by d.c. signal on separate pilots

Transmitting a tripping signal to a remote circuit breaker in addition to tripping the local one is an obvious control

function; where the distance is small there is little special to note. For instance, a generator main circuit breaker and field circuit breaker have sometimes been arranged mutually to intertrip. This practice is not now considered desirable and is referred to here purely as an example.

Where rather larger distances are involved, intertrip receive relays are likely to be required. For route lengths of, say, 100–1000 metres, these can be simple attracted armature type elements, but some protection against spurious operations being caused by induced voltages is usually provided by a copper slug on the electromagnet core which makes the relay insensitive to alternating current of quite a high value.



- $L1, L2$  Reactors  
 $M1, M2$  Metrosils (non-linear resistor)  
 $R$  Relay moving coil element

Figure 18.2 Type DBM4 surge-proof intertripping receive relay for shunt connection.

For intertripping over longer distances, as in its typical applications to feeder circuits, or if the exposure of the pilots to inductive interference is considered to be severe, a greater degree of discrimination between a.c. and d.c. currents is needed. So-called 'surge-proof' relays have been designed, most of them based on the permanent magnet moving coil type of element. This is inherently a d.c. type of relay element possessing a considerable degree of immunity to alternating currents; nevertheless, high values of a.c. will produce a vibratory motion of the coil which will also be subject to large transient deflections when the current starts or ceases. Auxiliary circuits are therefore added to increase the ability to withstand interference.

Relays are designed to be of either high or low impedance, the former being used to receive signals over separate pilots, the latter in series with the pilots of a differential protection scheme. Typical relays and schemes are described below.

#### High impedance relay for shunt operation over separate pilots

The type DBM4 shunt operated relay is shown in Figure 18.2.

The normal d.c. intertripping signal flows through the relay, the voltage drop being insufficient to pass appreciable current through the shunting Metrosil unit. A small induced alternating current will not affect the relay; if a substantial alternating current is received, the relatively high impedance of the reactor  $L1$  in series with the relay will divert a major proportion of this current through the Metrosil shunt  $M1$ .

When interference is superimposed on a genuine intertrip signal, the reduction in the resistance of the Metrosil shunt  $M1$  could result in the diversion of d.c. as well, to the detriment of relay operation. This effect is countered by the reactor  $L2$  and the parallel-connected Metrosil unit  $M2$ ; this combination is reduced in effective resistance and therefore increases the value of direct current signal when a large amount of a.c. is superimposed.

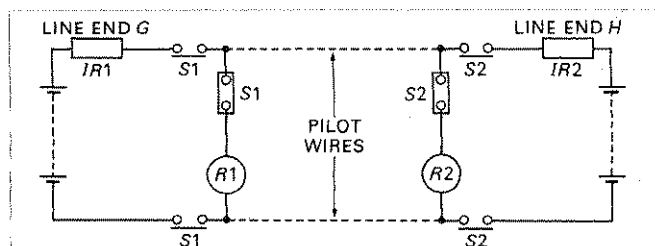
This relay is capable of operating with 0.015 A d.c. and of

remaining stable when subjected to 5 A of a.c. interference. It will withstand 5 kV between the pilot circuit and earth. In the normal application, an intertripping signal of 0.04 A is used, producing relay operation in 0.06 seconds.

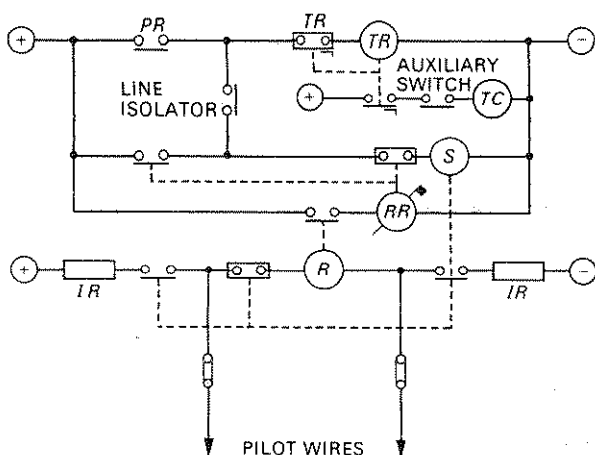
Figure 18.3 shows the circuit arrangement for a two-way intertripping scheme; part (a) shows the complete pilot circuit and part (b) shows typical tripping arrangements for one end.

When designing such a circuit it is important to ensure that the receive relay is not operated by the send relay at the same end and, conversely, that the receive relay does not by its operation establish a new intertrip send sequence. If these precautions are overlooked there is a possibility of the circuit becoming 'locked-up' in the operated condition and being difficult to reset. If the sequence in Figure 18.3 is followed, these conditions will be observed.

When the pilots follow the route of the power line, system fault currents may induce a high e.m.f. in the pilot line. A value of 0.3 volts per primary ampere-mile is possible, but the presence of metal sheaths on the power cable and pilot cable, if earthed at each end, will reduce the value of induced e.m.f. substantially. In the case of an overhead line, the degree of proximity of a pilot cable, the existence or otherwise of a continuous earth conductor and the effect of an earthed sheath on the pilot cable all need to be considered. Even so, a large e.m.f. can be induced. The e.m.f. is nominally equal in both pilot cores, and is therefore an insulation stress to earth. The relay described above is insulated to withstand such a stress up to 5 kV, or 15 kV if required.



(a) BASIC INTERTRIPPING CIRCUIT



(b) TYPICAL TRIPPING CIRCUIT FOR ONE END

PR Protective relay  
RR Repeat relay  
TC Trip coil of circuit breaker  
TR Tripping relay  
R Intertrip receive relay  
S Intertrip send relay  
IR Injection resistor

Figure 18.3 Two-way intertripping scheme using pilot wires.

Although a nominally equal stress is induced in each core, a small transverse voltage may possibly be caused by asymmetries of construction, but the value is unlikely to exceed 0.1% of the end-to-end e.m.f. and is not usually a problem to this type of relay. Imbalance in the terminal capacitance can sometimes result in the circulation of some induced current but the degree of surge-proofing quoted above is likely to be adequate for such contingencies. However, it is important not to attempt to relieve the induced stress by applying any form of surge diverter to the pilot circuit. Spark gaps, neon tubes or non-linear resistors are equally prohibited, since such devices may in operating short-circuit the pilots or produce a state of unbalance that can, in effect, change the longitudinal induced e.m.f. into a loop voltage that will bring an excessive circulation of interfering current.

It follows from the above remarks that the pilot circuit must be insulated to withstand the maximum induced voltage that can occur. This applies not only to the pilot cable, relays and other directly-connected equipment, but also to the battery used for sending the intertripping signal. In cases where the induced voltage is high, that is, more than a few hundred volts, it is undesirable to use the general station battery, since such use could result in the following effects:

- The induced voltage at the time of an intertripping operation could be applied via the battery to all the station d.c. wiring, with the consequent high insulation stress and risk of breakdown.
- The stress in (a) could result in a large charging current flowing into the wiring capacitance. This might cause unwanted intertripping, or interfere with the functioning of other relays.
- The high voltage momentarily applied to the station d.c. wiring could be dangerous to any personnel treating any such wiring as a low voltage circuit.

The problem can often best be solved by supplying the intertripping equipment from a small battery reserved for this purpose and mounted on a suitably insulated support. The battery may be trickle-charged, in which case the charger must be used for this battery only and have a standard of insulation appropriate to the pilot circuit; alternatively, the battery may be a portable unit, contained in a convenient crate and interchanged for recharging on a regular schedule.

### 18.2.2

#### Intertripping by d.c. signal superimposed on unit protection system pilots

When intertripping is required in addition to differential feeder protection, economy can be achieved by using one pilot circuit for both functions. A low impedance relay type DBS4 is available for this purpose, operating in series with the pilot circuit without interfering with the performance of the differential scheme. The principle of the relay is shown in Figure 18.4.

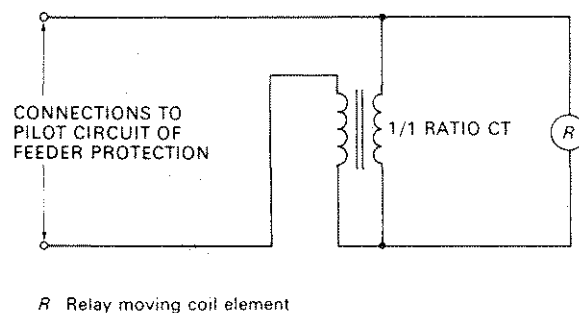


Figure 18.4 Type DBS4 low impedance surge-proof intertrip receive relay for series connection.

The 1/1 current transformer connected as shown diverts any a.c. input round its windings (primary and secondary) and so past the relay element, which, again, is of the permanent magnet moving coil type. The resistance of the windings is proportioned so that the greater part of an applied d.c. signal flows via the primary winding of the transformer to the moving coil element.

The relay will operate with 0.032 A d.c. applied; its impedance is only 3.5 ohms and so has little effect on any pilot wire scheme with which it may be used. The relay will remain stable with 2 A of a.c. induced in the pilot circuit.

A more elaborate relay, type DBSA4, is surge-proof to a 5 A level. This relay, shown in Figure 18.5, is similar to a DBS4 relay, but with an extra bias winding and an auxiliary contactor element.

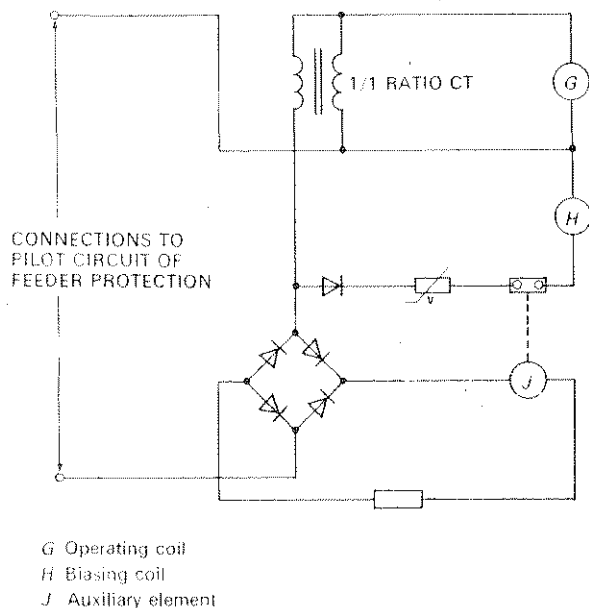


Figure 18.5 Type DBSA4 surge proof intertrip receive relay for series connection.

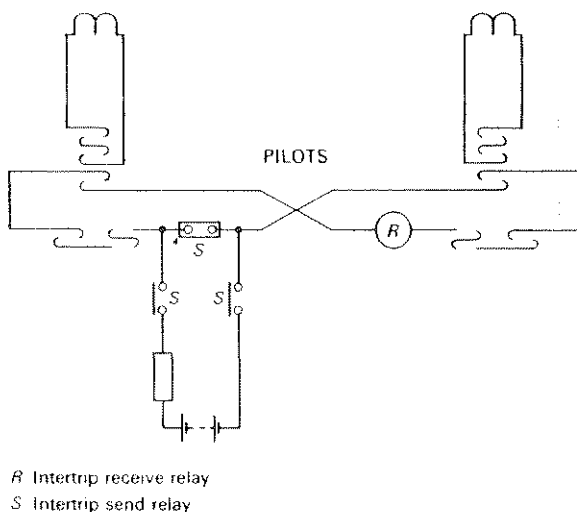


Figure 18.6 One-way intertripping superimposed on pilots of Translay differential protection.

Up to about 1.5 A, little current flows in the bias winding because of the series-connected non-linear Metrosil unit. The relay remains stable as explained for the DBS4.

Above this level of current, half-cycle pulses of current begin to flow through the diode and the bias coil. This

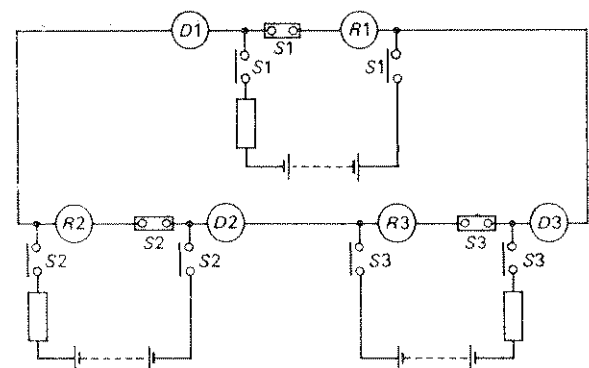
additional restraint is needed only to control the transient impulse which would otherwise affect the relay at the onset of severe a.c. interference. The bias is removed after a brief interval by the auxiliary element to ensure that a legitimate intertrip will not be inhibited.

The low impedance relays are used in conjunction with differential feeder protection as shown in Figure 18.6. This shows one-way intertripping added to an electromechanical Translay protection system; two-way intertripping is arranged as in Figure 18.3.

### Intertripping for multi-terminal lines

When intertripping is required between all the ends of a multi-terminal line, the shunt arrangement can result in unequal current distribution because of pilot resistance.

Another method using series relays is shown in Figure 18.7. It will be noted that the several batteries, each with its own injection resistance, are arranged to circulate current round the pilots in the same direction. One battery is capable of energizing the whole circuit to a satisfactory current value. When several operate together, the electro-motive forces are added, but the injection resistance for each sending end is also inserted. The current therefore does not greatly increase nor does the voltage between the pilot wires rise unduly at any point. Any number of ends can therefore mutually intertrip, provided only that the total pilot loop resistance is not excessive; for 110 volt batteries a pilot loop of up to 1000 ohms would be satisfactory.



D1, D2, D3 Differential relays  
R1, R2, R3 Intertrip receive relays  
S1, S2, S3 Intertrip send relay contacts

Figure 18.7 Series injection intertripping for multi-ended circuit using protection pilots.

### 18.2.3

#### Intertripping by voice frequency or super-imposed carrier signalling

For details of these methods see Chapter 8.

### 18.2.4

#### Interference with unit protection system

Limitations in the location of current transformers or the performance of the primary protection can produce a situation in which a fault in a position requiring the circuit to be isolated is seen as a through fault by the unit protection. A typical example is discussed in Section 15.12 and illustrated in Figure 15.26(b). Because the current transformers are mounted only on the feeder side of the circuit breaker, a fault between the current transformers and the breaker is in the zone of the busbar protection and external to the feeder zone. The circuit breaker will be tripped, but fault power may still be supplied through the feeder. It is therefore necessary to intertrip the remote feeder breaker.







# Industrial power system protection

- 19.1 Introduction
- 19.2 Busbar arrangement
- 19.3 Discrimination
- 19.4 MCB fuses
- 19.5 Industrial circuit breakers
- 19.6 Protective relays
- 19.7 Relay co-ordination
- 19.8 Fault current level determination
- 19.9 Automatic transfer systems
- 19.10 Voltage unbalance protection
- 19.11 Power factor correction
- 19.12 Insulation resistance monitoring
- 19.13 Systematic testing
- 19.14 Protection of cables
- 19.15 Power factor correction capacitors

## 19.1

As industrial processes and plants have become more complex and extensive, the demand for improved reliability of electrical power supplies has also increased. The potential costs of outage time following a failure of the power supply or plant have accordingly risen dramatically as well.

This has brought increased attention to the protection and control of industrial power supply systems, in which many of the techniques which have been evolved for HV power systems may be applied to lower voltage systems also, though frequently on a reduced scale. However, industrial systems have many special problems which have warranted individual attention and the development of individual solutions.

The introduction of automation techniques into the factory has led naturally to consideration of more automation of the power supply also, to improve reliability and efficiency.

Also recent legislation, such as the UK Energy Act: 1983, has heightened the involvement of industrial organizations in the co-generation of electricity, with mutual benefits to the power utility and the consumer.

## 19.2

The arrangement of the busbar system is obviously very important, and can be quite complex in some very large industrial systems. However, in most systems a single busbar divided into sections by a bus section breaker is common, as illustrated in Figure 19.1. Considering a medium sized industrial supply system illustrated in Figure 19.2, in more detail, it will be seen that not only are duplicate supplies and transformers used, but also certain important loads are segregated and fed from an 'Essential Services Board'. This enables maximum utilization of the standby generator facility which, for economy, is usually of the turbo-charged diesel-generator type. In industrial processes where waste steam or gas is available, they will probably be the natural choice for driving the prime mover. Automatic starting is usual, the output breaker or contactor closing to allow the generator to take over load after an interval of about 10 seconds.

A further advantage of this system layout is that it helps to ensure the closely regulated, filtered or even 'no-break' power supply increasingly required by industries using computers and other sophisticated electronic equipment.

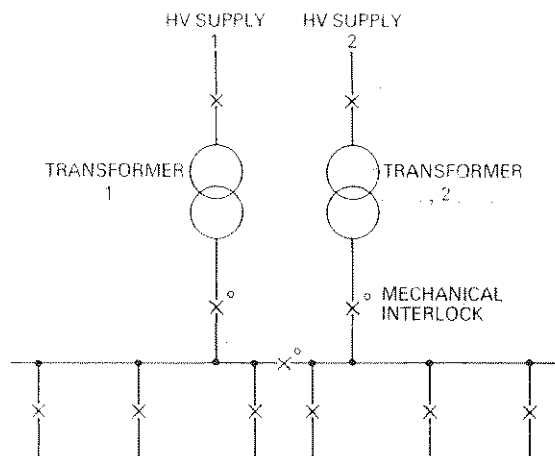


Figure 19.1 Duplicate supply single busbar with section breaker

In this event the 'Essential Services Board' can be used to supply a suitable power equipment for this specialized type of plant, whilst retaining the advantage of the standby generator set.

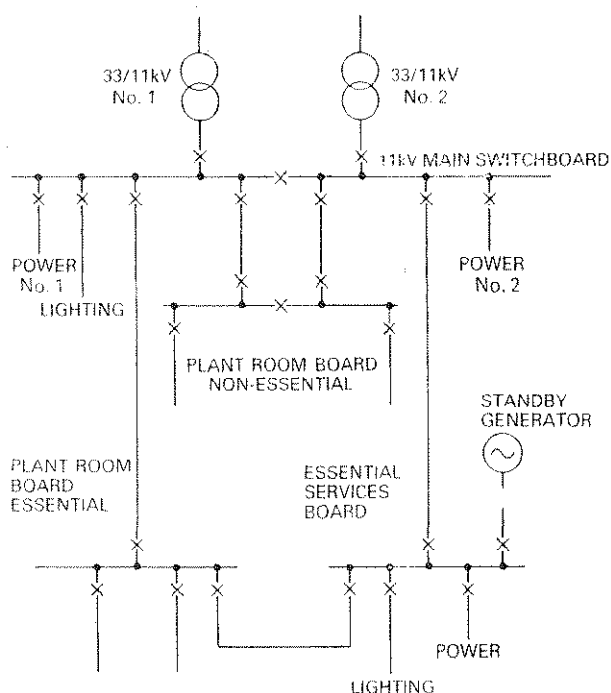


Figure 19.2 Typical industrial supply system.

### 19.3

Protective equipment works in conjunction with switch-gear. On a typical industrial system feeders and plant will be protected mainly by circuit breakers, associated over-current and earth fault relays and fuses, with the objective of obtaining 'discrimination', which is the ability to select and isolate only the faulty part of the system.

### 19.4

The protective device nearest to the actual point where the

industrial power is used is most likely to be a fuse, or system of fuses, and it is important that consideration is given to the correct application of this most important item. Typically a High Rupturing Capacity (HRC) fuse consists of a ceramic body containing specially designed fusible elements usually of silver or an associated alloy, the elements being connected to metal end caps which also serve to seal the body after it has been filled with some granulated quartz. The time required for melting the fusible element depends on magnitude of current. Vaporization occurs on melting and there is fusion between the vapour and the filling powder leading to rapid arc extinction.

Fuses have a valuable characteristic known as 'cut off' illustrated in Figure 19.3. When an unprotected circuit is subjected to a short circuit fault, the current rises towards

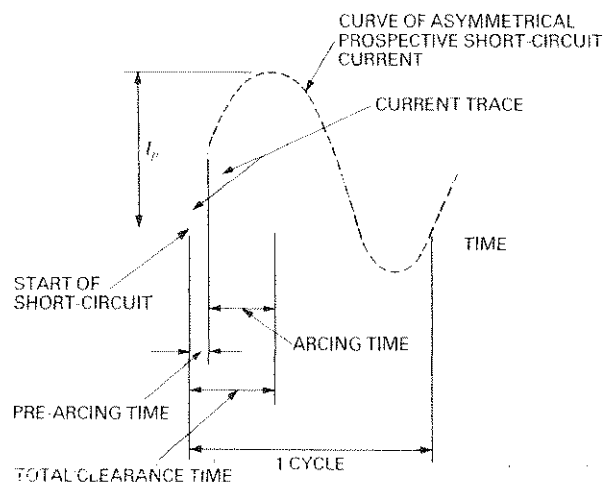


Figure 19.3 HRC fuse cut off feature.

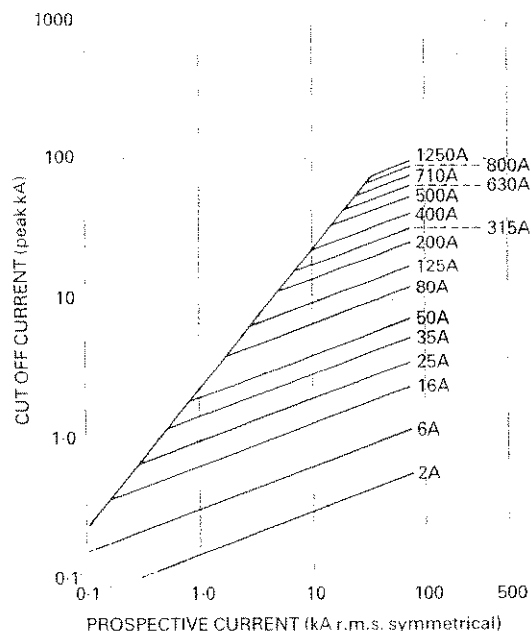


Figure 19.4 Typical fuse cut off current characteristics.

a 'prospective value'. The short circuit current is usually interrupted before it can reach the prospective value, in the first quarter to half cycle of short circuit; the rising current is stopped by the melting of the fusible element with the current dying away to zero during the arcing period.

Since the electromagnetic forces on busbars and connections carrying short circuit current are related to the square of the current, it will be appreciated that 'cut off' significantly reduces the mechanical forces produced by the fault current and which are liable to distort the busbars and connections. A typical example of 'cut off' current characteristics is illustrated in Figure 19.4.

Fuses are often connected in series electrically and it is essential that they should be able to discriminate against each other at all levels. Positive discrimination is obtained when the larger fuse (called the 'major' fuse) remains unaffected by fault currents which are cleared by the smaller fuse (called the 'minor' fuse).

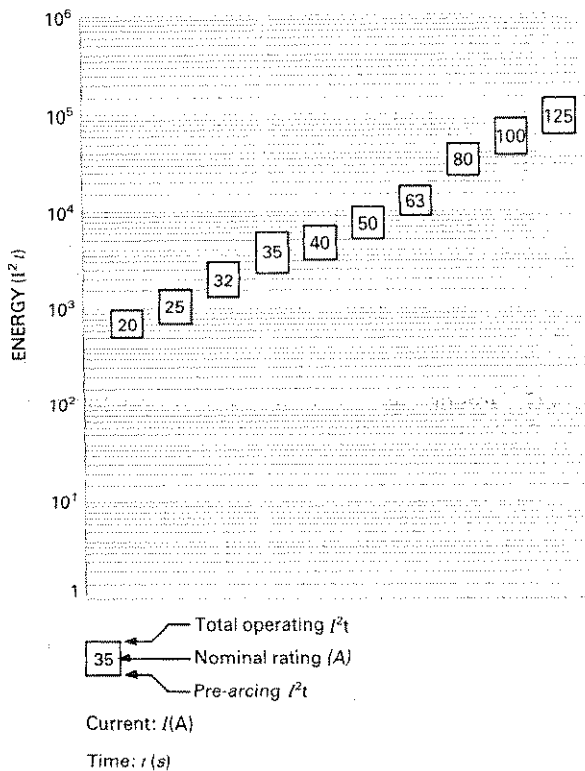


Figure 19.5 HRC fuse energy characteristics.

The fuse operating time can be considered in two parts:

- The time taken for fault current to melt the element, known as the 'pre-arcing time'.
- The time taken by the arc produced inside the fuse to extinguish and isolate the circuit, known as the 'arcing time'.

The total energy dissipated in a fuse during its operation consists of 'pre-arcing energy' and 'arc energy'. The values are usually expressed in terms of  $I^2t$ , where  $I$  is the current passing through the fuse and  $t$  is the time in seconds. Expressing the quantities in this manner forms an assessment of the heating effect which the fuse imposes on associated circuit equipment during its operation under fault conditions.

To obtain positive discrimination between fuses, the total  $I^2t$  value of the minor fuse must not exceed that of the pre-arcing  $I^2t$  value of the major fuse.

During breaking capacity tests carried out to the British Standard Specification, the worst arc energy conditions have been found to produce  $I^2t$  values of twice the pre-arcing value of a given fuse, so this factor must be taken into account when selecting a major fuse to discriminate on high fault conditions.

In general therefore, the major fuse should be selected to have a rating of twice that of the minor fuse, but the  $I^2t$  characteristics such as those shown typically in Figure 19.5 can be used to assess discrimination when it is necessary to resort to the use of a smaller ratio to achieve an optimum compromise in terms of discrimination and cost.

#### 19.4.1 HRC fuse applications

An example of the application of fuses is based on the arrangement in Figure 19.6 which shows an unsatisfactory scheme with commonly encountered shortcomings. From this it can be seen that fuses  $H$ ,  $J$  and  $K$  will discriminate with fuse  $G$ , but the 400 A sub-circuit fuse  $L$  may not discriminate with the 500 A sub-circuit fuse  $H$  at higher levels of fault current.

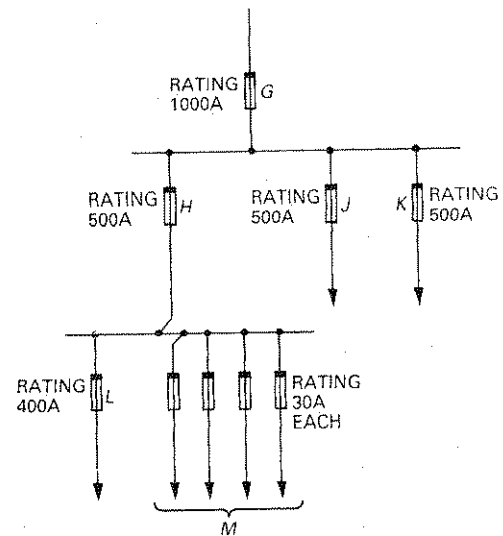


Figure 19.6 Effect of layout on discrimination.

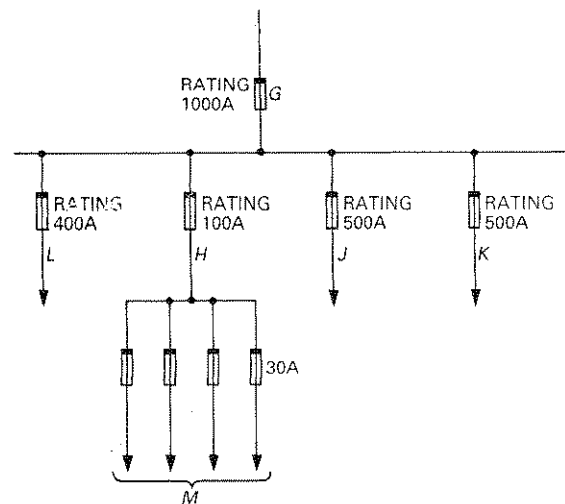


Figure 19.7 Correct discrimination.

The solution illustrated in Figure 19.7 is to feed the 400 A circuit  $L$  direct from the busbars. The sub-circuit fuse  $H$  may now have its rating reduced from 500 A to a value, of say 100 A, appropriate to the remaining sub-circuit. This arrangement now provides a discriminating fuse distribution scheme satisfactory for an industrial system.

The introduction of cables having PVC insulation originally led to problems concerning fuse protection since PVC cables have a lower thermal capacity than that of paper

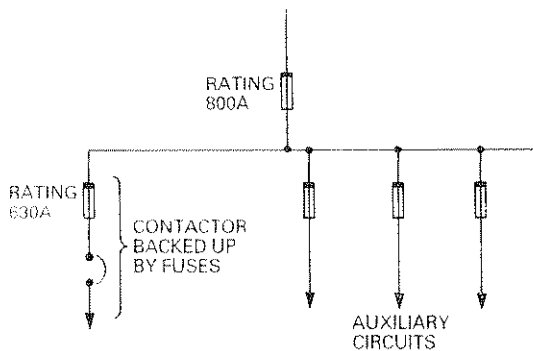


Figure 19.8 Example of back-up protection

insulated types and may have to be run at a reduced rating. Present practice allows a PVC cable to be loaded to its full nominal rating only if it has 'close excess current protection'. This degree of protection can be given by means of a fuse link having a 'fusing factor' not exceeding 1.5 where:

$$\text{Fusing factor} = \frac{\text{Minimum fusing current}}{\text{Current rating}}$$

Standard HRC type 'T' fuse links can provide this protection.

However, there are industrial applications where discrimination is a secondary factor. In the application shown in Figure 19.8, the load in one sub-circuit is controlled by a contactor which, for economy, is of a type and size having low fault-handling capacity. A rating of 630 A is selected for the minor fuse in the contactor circuit to give back-up protection within the through-fault capacity of the contactor, whereas the major fuse of 800 A is chosen to clear faults in the busbar zone and would not adequately protect the contactor. Discrimination between the two fuses will be obtained only at low prospective fault currents, but this may be acceptable where the requirement for back-up protection predominates over discrimination.

The capability of HRC fuses can be influenced by high ambient temperatures. Most fuses are suitable for use in ambient temperatures up to 35°C, but for some fuse ratings, derating may be necessary at higher ambient temperatures and manufacturers' published literature should be consulted for the amount of derating to be applied.

The manufacturers' literature should also be consulted when fuses are to be applied to motor circuits. In this application the fuse provides short circuit protection but must be selected to withstand the starting current of the motor, together with any starting system surges, and also carry the normal full load current continuously without deterioration. Tables of recommended fuse sizes for both 'direct on line' and also 'assisted start' motor applications are usually given.

Another important application is the protection of semiconductor devices, since these are extensively used in industry. Silicon diodes and thyristors are commonly used in power rectification and inverter equipment and semiconductors are frequently encountered in control systems. The application of semiconductors most efficiently and economically leads to devices having small physical size with limited overload capacity, so rapid interruption of current must take place to protect the devices from the high currents flowing under fault conditions. Standard HRC fuses are not suitable for this application and special fuses with minimum let-through of current and energy, such as GEC ALSTHOM type 'GS' fuse links, have been developed for the protection of semiconductor devices.

Fuse characteristics of suitable variety and accuracy are generally readily available, enabling fuses to be applied

wherever the requirements are known. HRC fuses remain consistent and stable in service without calibration and maintenance. Indeed, the property of non-deterioration is one of the most significant factors in accuracy of discrimination which has been proved to a degree of sensitivity well within the requirements of normal distribution systems.

Failure to achieve discrimination owing to incorrect choice of fuses may result in unnecessary disconnection of supplies, but if both the major and minor fuses are HRC devices of proper design and manufacture, this need not endanger the associated cables.

The HRC fuse is a most important item in industrial protection, whether mounted in a distribution fuseboard or as part of a fuse-switch. The latter is regarded as a vital part of LV circuit protection, combining as it does safe circuit making and breaking with an isolating capability achieved in conjunction with the reliable short-circuit protection of the HRC fuse.

## 19.5

Some parts of an industrial power system are most effectively protected by HRC fuse links, but there are parts of such systems where the replacement of blown fuse links would be particularly inconvenient. In these locations circuit breakers may be used instead, the requirement being for the breaker to interrupt the maximum possible fault current successfully without damage to itself. In addition to fault current interruption the breaker must quickly disperse the resulting ionized gas away from the breaker contacts, to prevent re-striking of the arc, and also away from other live parts of equipment to prevent breakdown elsewhere. The breaker, its cable or busbar connections, and the breaker housing, must all be constructed to withstand the mechanical forces resulting from the magnetic fields produced by the highest levels of fault current to be encountered.

### 19.5.1

#### Breaker operating mechanisms

Circuit breakers may be operated either manually by handle or lever, or automatically, by motor, direct solenoid, or by spring charging. In the latter type a spring is wound up by a motor and held in tension, so that when the breaker is to be closed a small solenoid is energized to release the spring energy to close the breaker.

With all the mechanisms, once the breaker contacts are firmly closed, the breaker mechanical closing linkage latches the contact mechanism firmly in position. It is usual for a number of auxiliary contacts of various configurations to be provided on the breaker for external use in indication and control circuits. In the case of electrically operated breaker mechanisms, an internally connected 'late break' auxiliary contact is provided to disconnect the operating circuit after the breaker main contacts are latched home.

Most breaker operating mechanisms are 'trip free', which means that the operating handle or lever does not undergo violent movement when the breaker latching mechanism is released.

### 19.5.2

#### Breaker tripping mechanisms

The tripping mechanism is a linkage operating to release the latching mechanism, so permitting the main breaker contacts to open rapidly under spring or other assistance. Operation of the tripping linkage can be initiated by energization of a solenoid tripping coil.

Internal overload trip devices are often included, these being either of the instantaneous or time delayed magnetic type or sometimes of the thermal type, in each case acting directly on the tripping linkage.

Many breakers also include an undervoltage trip unit, often with a fixed setting, arranged for operation on a falling voltage between 70% and 30% of the nominal rating. The unit operates on the tripping linkage directly, and resets typically at around 85% of the nominal voltage.

The types of circuit breaker most frequently encountered in industrial systems are described in the following Sections.

### 19.5.3

#### Miniature and moulded case circuit breakers

These types of circuit breaker are extremely popular in industrial power distribution systems. They are similar in many ways, and although strictly speaking both types have moulded plastic housings, those bearing this reference in their title have the higher electrical ratings.

##### Miniature circuit breakers (MCBs)

MCBs are the smaller of the two types, both in physical size but more importantly, in ratings. The basic single pole unit is a small, manually closed, electrically or manually opened switch housed in a moulded plastic casing. Also contained within each unit is a thermal element, in which a bimetal strip will trip the switch when excessive currents pass through it. This element operates in line with a predetermined inverse-time/current characteristic. Higher currents, typically those exceeding 6–8 times rated current, trip the switch nominally instantaneously by actuating a magnetic trip overcurrent element. Neither part of the overall operation time characteristic is adjustable in MCB's.

These single pole units, defined by BS 3871: Part 1: 1965 (with revisions) are commonly coupled mechanically in groups to form 2 pole, 3 pole and 4 pole units, which are then assembled on to a rail, in rows, on a distribution board.

The units are rated at 415/240 V a.c. nominally, with a current rating of up to 100 A. Fault current breaking capacity is usually within 9 kA, which is denoted as 'M9', but can be as high as 16 kA.

The ratings make the MCB's suitable for industrial, commercial or domestic applications, for protecting such as cables, lighting and heating circuits and also the control and protection of low power motor circuits. They may be used instead of fuses on individual circuits, and are usually 'backed-up' by fuses in the main feed to the distribution board, which gives the MCB plus fuses combination a much higher fault current interrupting capability.

Various accessory units, such as isolators, timers, undervoltage release or shunt trip release units, may be combined with any MCB to suit the particular circuit to be controlled and protected. When the maximum expected current for earth faults is relatively low a further unit, the residual current device (RCD), formerly known as an earth leakage circuit breaker (ELCB), may be combined with the MCB. The RCDs contain miniature core balance current transformers, which, by embracing all three (phases) or four (3 phases plus neutral) conductors provides a sensitivity to earth faults from within the typical range of 0.05% to 1.5% rated current, dependent on the RCD selected.

##### Moulded case circuit breakers (MCCBs)

These circuit breakers are broadly similar to MCBs but have the following important differences:

- The maximum ratings are higher, with voltage ratings up to 1000 V a.c. or 1200 V d.c. Current ratings generally exceed 100 A and may be up to 2.5 kA or higher. The current breaking capacities are also higher, up to 50 kA or so, dependent upon power factor.
- The breakers are larger, commensurate with the level of ratings. Although generally available as single, double or triple pole units, the multiple pole units are not usually a

combination of single pole modules, and instead have a common housing for all the poles. The switch for the neutral circuit, however, is usually a separate device when required, coupled to the multi-pole MCCB.

c. Though also of the thermal/magnetic type, the operating levels of the magnetic and thermal element of these circuit breakers may both be adjustable, particularly in the larger MCCBs.

d. Because of their higher ratings, MCCBs are usually positioned in the power distribution system nearer to the power source than the MCBs.

e. The appropriate specifications are: IEC 157-1: 1973, IEC 157-1A: 1976 and BS4752: Part 1: 1977.

The degree of inverseness of the magnetic or thermal timed trip, together with the necessity for, or size of, back-up fuses varies with make and size of breaker, and when applied to a system discrimination with other protection must be considered, as outlined in Chapter 9.

An example of co-ordination involving a moulded case circuit breaker and a protection relay is shown in Figure 19.9. This shows part of a 415 V switchboard on a large industrial complex, with the distribution circuits from the 415 V busbar being controlled either by 400 A fuses or

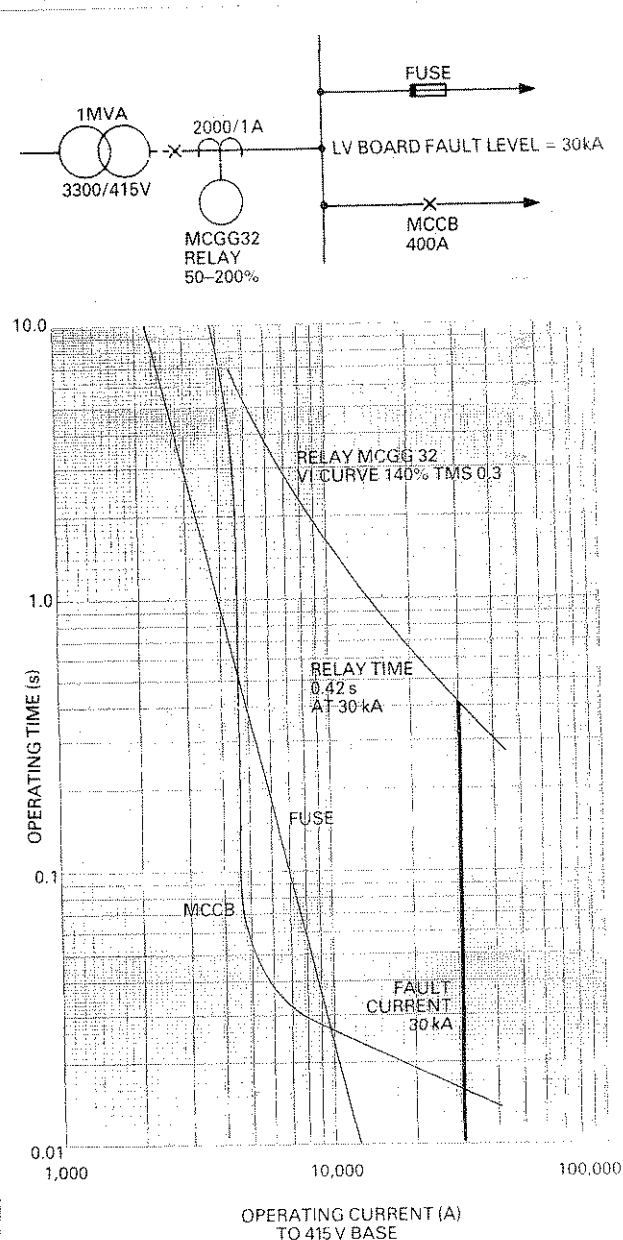


Figure 19.9 Example of protection co-ordination.

400 A MCCBs. The 1 MVA 3,300/415 V transformer feeds the LV board via a breaker, which is equipped with a static modular overcurrent relay type MCGG having a setting range of 50% to 200% of rated current and fed from 2000/1 A CTs.

Discrimination is required between the relay and both the fuse and MCCB up to the fault level of the board which is 30 kA.

Discriminatory settings may be obtained as follows:

#### i. Determination of relay current setting

The relay current setting chosen must not be less than the full load current level and must have enough margin to allow the relay to reset with full load current flowing. The latter may be determined from the transformer rating:

$$FLC = \frac{kVA}{kV \times \sqrt{3}} A = \frac{1000}{0.415 \times 1.73} A = 1393 A$$

With the CT ratio of 2000/1 A and allowing for the MCCB relay resetting at 95% of the nominal current setting, it would appear that a current setting of between 75% and 100% would be satisfactory. However, choice of a value at the lower end of this current setting range would move the relay characteristic towards that of the MCCB and thereby discrimination may be lost at low fault current levels. It is therefore prudent to select initially a relay current setting of 100%.

#### ii. Fuse and MCCB characteristic

The time/current characteristics of both the 400 A fuse and the MCCB are plotted directly on to log-log paper.

#### iii. Relay characteristic and time multiplier selection

When protection relay settings are being considered to obtain discrimination with fuses and other devices having steeply inverse characteristics, it is usual to select firstly a relay characteristic of the extremely inverse type. On the MCGG relay, this characteristic is obtained by switching the curve selection switches to the positions for 'EI'.

From the Figure it may be seen that at the fault level of 30 kA the fuse will operate in less than 0.01 s and the MCCB operates in 0.016 s. If a grading margin of 0.4 s is applied, the required relay operating time becomes  $0.4 + 0.016 = 0.416$  s. With a CT ratio of 2000/1 A and a relay setting of 100% the relay  $PSM = \frac{30,000}{2,000} = 15$

At this PSM of 15 and with a maximum TMS setting of 1.0 the extremely inverse curve gives a relay operating time of 0.357 s, which is too fast to give adequate discrimination and indicates that the relay extremely inverse curve is too severe for this application. Turning to the 'very inverse' relay characteristic, also available on the same MCGG relay (reference 'VI') with  $PSM = 15$  and  $TMS = 1.0$  the relay operation time is found to be 0.964 s. To obtain the required relay operating time of 0.416 s the necessary TMS setting =  $\frac{0.416}{0.964} = 0.431$  say 0.5.

As previously mentioned, the use of a form of inverse characteristic makes it advisable to check discrimination at the lower current levels also at this stage. At  $PSM = 2.0$ , equal to 4000 A, the relay will operate in  $13.5 \times 0.5 = 6.75$  s, which does not give discrimination. So the relay characteristic needs to be moved away from the MCCB characteristic, a change which may be achieved by selecting a higher relay current setting.

With a higher relay current setting of 140% and with a CT ratio of 2000/1 A the relay  $PSM = \frac{30,000}{2,800} = 10.7$ .

At this PSM and with  $TMS = 1.0$  the relay 'VI' curve gives a relay operating time of 1.35 s. To obtain the required relay

operating time of 0.42 s the required TMS setting =  $\frac{0.42}{1.35} = 0.311$  say 0.3.

With the relay set at the 140% setting and  $TMS = 0.3$ , the following points may be obtained for plotting the required relay characteristic.

| Relay PSM | Primary current (A) | Operating time (s)        |
|-----------|---------------------|---------------------------|
| 1.6       | 4480                | $22.5 \times 0.3 = 6.75$  |
| 1.8       | 5040                | $16.87 \times 0.3 = 5.06$ |
| 2.2       | 6160                | $11.25 \times 0.3 = 3.37$ |
| 3.0       | 8400                | $6.75 \times 0.3 = 2.02$  |
| 5.0       | 14000               | $3.375 \times 0.3 = 1.01$ |
| 10.0      | 28000               | $1.5 \times 0.3 = 0.45$   |
| 15.0      | 42000               | $0.964 \times 0.3 = 0.29$ |

The above points, when plotted against the fuse and MCCB characteristics, confirm that the MCGG relay very inverse (VI) characteristic, with a relay current setting of 140% rated current and TMS setting = 0.3 gives satisfactory discrimination up to the maximum fault level of 30 kA.

### 19.5.4

#### Oil circuit breakers (OCBs)

Oil circuit breakers have been very popular for many years on industrial supply systems at voltages at 3.3 kV and above.

In this type of breaker the main contacts are housed in an oil-filled tank, the oil acting as the arc-quenching medium.

Breaker operating and tripping systems are generally as previously described.

These breakers use the energy from the arc current for arc extinction. The arc produced by the contacts opening to interrupt current causes dissociation of the hydrocarbon insulating oil into hydrogen and carbon, and it is the hydrogen that is used to extinguish the arc. The carbon produced mixes with the oil, and as it is unfortunately a conductor, the oil must be changed after several fault clearances, when the degree of contamination reaches an unacceptable level.

Some modern designs of OCB use reduced volumes of oil and these are known as 'low oil' or 'minimum oil' types. Because of the fire risk involved with oil, precautions such as the construction of fire/blast walls have to be taken when OCBs are installed.

### 19.5.5

#### Vacuum circuit breakers (VCBs)

In recent years this type of circuit breaker has tended to replace OCBs in popularity on industrial systems rated at 3.3 kV and above.

The principle of operation is that the main contacts are housed within a vacuum, in an insulating cylinder of glass or ceramic having metal end plates supporting the contacts.

A flexible vacuum seal is provided for the moving contact by means of metal bellows. The contacts are surrounded by a cylindrical metal shield which protects the insulator surface from the arc products and also controls the electrical stress along the insulator surface when the contacts are open. This vacuum device is often referred to as a 'vacuum interrupter'.

One vacuum interrupter per phase is usually used in 11 kV breakers, a single operating rod being used to close all three phases simultaneously. On some designs of 33 kV breakers, two vacuum interrupters are used in series per phase.

The closing mechanism employed in VCBs is usually of the

solenoid or spring-closing type. Contact wear is very low because the arc takes place in a vacuum.

Compared with oil circuit breakers, vacuum breakers have no fire risk and have high reliability with long maintenance free periods.

Some manufacturers design vacuum breakers to be a direct replacement for their oil circuit breaker designs, to facilitate the uprating or modernizing of existing switchboards.

Vacuum interrupters are also increasingly being used in the form of vacuum contactors, with HRC fuses, in HV motor starter applications.

### 19.5.6

#### Air circuit breakers (ACBs)

Air circuit breakers are frequently encountered on industrial systems rated at 3.3 kV and below.

This type of breaker operates on the principle that when the main contacts open, the arc produced is controlled by directing it into an arc chute. Here the arc resistance can be increased and the current reduced to the point where the arc cannot be maintained by the circuit voltage and the circuit is cleared.

Arc chute designs vary; one type stretches and cools the arc by means of specially shaped insulating plates. Another type uses metal plates to split the arc up into a number of series arcs and also assists cooling by convection.

In all ACBs the forces directing the arc into the chute are the electromagnetic and thermal forces of the arc itself, usually supplemented by those from a current fed 'blow-out' coil located at the base of the arc chute. To assist in the quenching of low current arcs, an air cylinder may be fitted to each pole to direct a puff of air across the contact faces as the breaker opens, so reducing contact erosion.

Operating and tripping mechanisms are similar to those used with OCBs.

Air circuit breakers for industrial use are usually withdrawable and constructed with a flush front plate making them ideal for inclusion together with fuse switches and MCBs in attractive, modular, multi-tier distribution switchboards, so maximizing the number of circuits within a given floor area.

### 19.5.7

#### Static breaker-mounted protection relay

The air circuit breaker is most usually encountered on the lower voltage industrial systems where the breaker acts as back-up to protective devices such as MCCBs and fuses located nearer the point of power utilization.

In some installations difficulty is experienced in selecting settings on the ACB's overcurrent device which will give satisfactory discrimination with the protective devices on the circuit beyond the breaker. To help alleviate this problem it is becoming common for ACBs to be fitted with a built-in solid-state overcurrent relay having ample ranges of setting adjustment.

Typical of such relays is the type CTZ, illustrated in Figure 19.10 and fitted to many GEC ALSTHOM air circuit breakers. As a departure from past practice the relay is located within the circuit breaker itself and is accessible through a removable grill on the breaker front panel.

The relay is 'self-powered', with the internal electronic circuitry being powered entirely by the input currents from the current transformers. Several types of CTZ relay are available; the CTZ61 is a three phase overcurrent relay with a selectable overall characteristic to suit a variety of system requirements, by a combination of inverse time and high set independent time overcurrent characteristics, as shown in Figure 19.11.

A selection of six inverse time characteristics is available controlled by two adjustable switches. One switch varies the pick-up current in six steps from 0.5 to 1.0 times the rated current,  $I_n$ , of the circuit breaker and the other switch varies the operating times in six stages from 2 to 20 seconds, calibrated at 6 times the relay setting current  $I_s$ . The settings of the high set independent time overcurrent elements are determined by two further switches; one

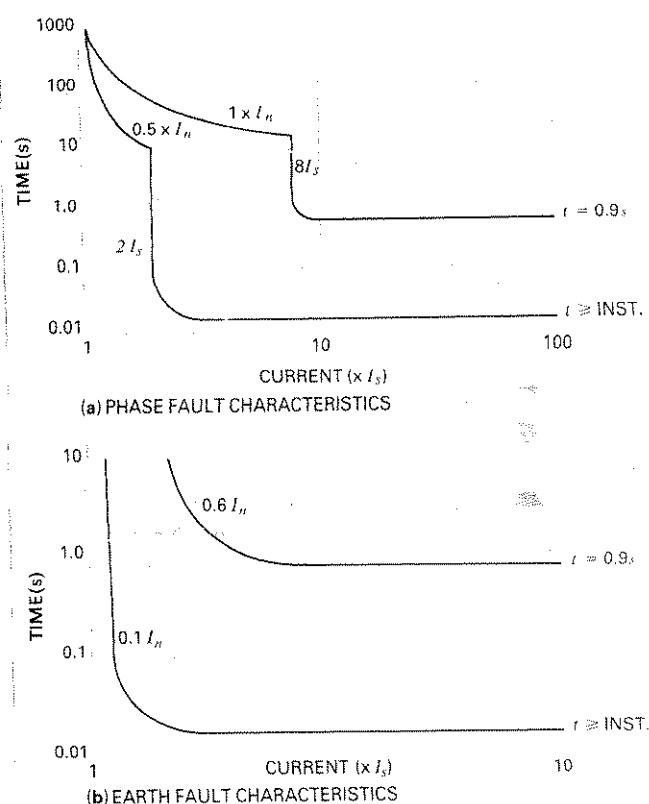


Figure 19.11 Operation characteristics of static, breaker-mounted overcurrent relay, type CTZ.

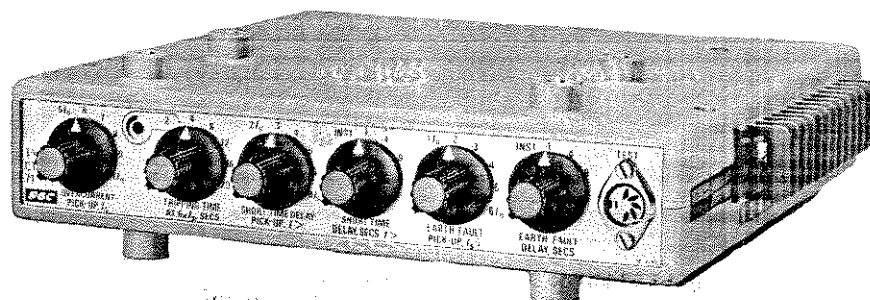


Figure 19.10 Relay type CTZ for circuit breaker mounting.



selects the point of changeover from I.D.M.T. to independent time and varies the pick-up current in six steps from 2 to 8 times setting current  $I_s$ , the other switch varies the operating time of the high set overcurrent unit from instantaneous, to 0.1 s, 0.4 s or 0.9 s. The four settings provided ensure that up to three circuit breakers in series can be arranged to discriminate with each other on the occurrence of a fault. The lower two settings, instantaneous and 0.1 second, are not designed to grade with each other and should be considered as alternatives for the lowest setting. For example, if a circuit breaker is feeding a motor or a sub-circuit containing fuses, the instantaneous setting could be chosen, but if the circuit breaker is feeding moulded case circuit breakers which have an instantaneous tripping time of around 20 milliseconds, then the lowest time setting to be chosen on the CTZ relay would be 0.1 seconds.

The CTZ71 is similar to the CTZ61 described, with an addition of an independent time earth fault element. An alternative pair of relays, types CTZ66 and CTZ76 are particularly suited to the simpler applications, having a dual inverse overcurrent characteristic and a fixed earth fault characteristic. All CTZ relays incorporate a thyristor-controlled tripping stage, in which a thyristor triggers the discharge of a charged capacitor, when the relay operates. This output is used to operate a sensitive actuator to trip the circuit breaker.

## 19.6

When the circuit breaker itself does not contain a protection relay such as a CTZ, then suitable relays will be mounted on a panel near the breaker. On industrial systems the most common protective relays are inverse time overcurrent relays usually fed from suitable protective type current transformers. Details of a well-proven electromechanical relay, type CDG and a more recent static design, type MCGG, are given in Sections 6.8.1 and 6.8.2 respectively. Phase connected overcurrent relays respond to current in the associated primary phases and their settings in terms of primary current must be greater than the normal load current. To ensure satisfactory performance during fault conditions, the minimum fault current for which operation is required must produce not less than twice the setting current in the relay.

The most frequent type of fault is an earth fault, and though phase connected overcurrent relays will detect earth fault currents above the relay setting, the earth fault current may be limited in magnitude by the neutral earthing impedance or by earth contact resistance.

More sensitive protection against earth faults can be obtained by using a relay element which responds only to the residual current of a system, since a residual component of current can exist only when a fault current flows to earth. The earth fault relay may therefore be given a setting lower than load current. The residual current component is extracted by connecting the line current transformers in parallel with the earth fault element, the overcurrent elements being connected in the individual current transformer phase leads.

It is important that the correct current transformer and relay connections arrangement is used for a particular system configuration. A variety of arrangements is illustrated in Figure 19.12.

On three wire systems, overcurrent relays are often provided on two phases only for economy. These will detect any interphase fault, so it is conventional to locate these two elements on the same phases at all relay locations. The earth fault relay connections are unaffected by this convention. It should be noted that on four wire systems, overcurrent elements are required on all three phases

to ensure operation of at least one element during phase to neutral faults. If sensitive earth fault protection is also required on this system, then four current transformers are necessary to ensure non-operation for unbalanced loads. Alternatively, a separate earth fault relay energized from a core-balanced current transformer may be used.

## 19.7

### 19.7.1 Co-ordination of earth fault relays in three phase four wire systems

To operate an industrial power system efficiently correct discrimination is required between all protection devices from the point of power utilization right up the circuit towards the source of power.

Appropriate settings must be calculated for each relay and the characteristics of all the protective devices on the circuit branch under consideration compared to ensure discrimination. This process is known as 'relay co-ordination' and is discussed in detail in Chapter 9.

### 19.7.1

#### Co-ordination of earth fault relays in three phase four wire systems

Several difficulties may be encountered in the application of earth fault relays to three phase, four wire systems, arising from the presence of the neutral busbar and the possibility of single phase loading.

If an earth fault relay is fed from residually connected line CTs a fourth identical CT, located on the neutral conductor, is required to ensure stability for through fault currents. This conductor may carry single phase load unbalance current, together with any harmonic currents produced by various items of load. If the neutral CT is omitted, neutral current is seen by the relay as earth fault current and the relay setting would have to be increased to prevent tripping under load conditions.

When a relay is residually connected, it may be difficult to obtain a sensitive effective setting because of CT magnetizing current and spill current arising from unequal CT saturation.

The alternative technique of energizing a relay from a core balanced type CT generally enables more sensitive effective settings to be obtained. When this method is applied to a four wire system it is essential that both the phase and the neutral conductors are passed together through the opening in the core balance unit.

The co-ordination of earth fault relays protecting four wire systems requires special consideration, particularly in the case of low voltage radial-fed installations, a popular configuration in industrial systems. Various methods of achieving optimum co-ordination have been suggested by Horcher\*

In general when both neutrals are earthed at the transformer, the neutral busbar in the switchgear creates a double neutral to earth connection, as shown in Figure 19.13(a). In the event of an uncleared feeder earth fault or busbar earth fault, with both the incoming supply breakers closed and the bus section breaker open, the earth fault current will divide between the two earth connections. Accordingly it will similarly divide between the relays and the neutral busbar, with the possibility that the circuit breaker on the unfaulted supply side will trip as well as the breaker on the faulted side.

If only one incoming supply breaker is closed, the earth fault relay on the energized side will see only a proportion of the fault current flowing in the neutral busbar. This not only significantly increases the relay operating time but also reduces its sensitivity to low level earth faults.

A configuration often adopted with four wire double fed systems is to use a single earth electrode connected to the mid-point of the neutral busbar in the switchgear as shown

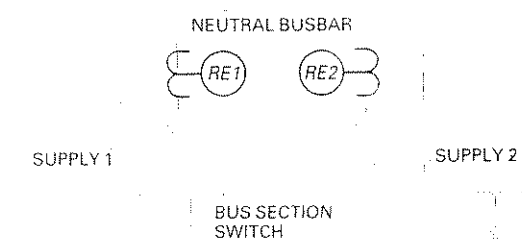
\*Overcurrent Relay Co-ordination for Double Ended Substations, George R Horcher, IEEE, Vol 1A-14 No. 6 1978.



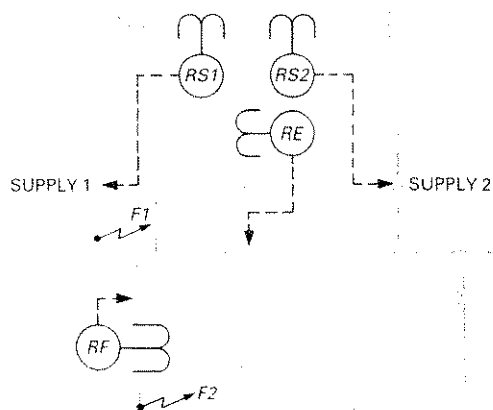
|     | CT connections | Phase elements | Residual-current elements | System                   | Type of fault                                   | Notes                                                                                                   |
|-----|----------------|----------------|---------------------------|--------------------------|-------------------------------------------------|---------------------------------------------------------------------------------------------------------|
| (a) |                |                |                           | 3Ph. 3w                  | Ph. - Ph.                                       | Petersen coil and unearthed systems.                                                                    |
| (b) |                |                |                           | 3Ph. 3w                  | (i) Ph. - Ph.<br>(ii) Ph. - E*                  | * Earth-fault protection only if earth-fault current is not less than twice p.o.c.                      |
| (c) |                |                |                           | 3Ph. 4w                  | (i) Ph. - Ph.<br>(ii) Ph. - E*<br>(iii) Ph. - N |                                                                                                         |
| (d) |                |                |                           | 3Ph. 3w                  | (i) Ph. - Ph.<br>(ii) Ph. - E                   | Phase elements must be in same phases at all stations. Earth-fault settings may be less than full load. |
| (e) |                |                |                           | 3Ph. 3w                  | (i) Ph. - Ph.<br>(ii) Ph. - E                   | Earth-fault settings may be less than full load.                                                        |
| (f) |                |                |                           | 3Ph. 4w                  | (i) Ph. - Ph.<br>(ii) Ph. - E<br>(iii) Ph. - N  | Earth fault settings may be less than full load, but must be greater than largest Ph. - N load.         |
| (g) |                |                |                           | 3Ph. 4w                  | (i) Ph. - Ph.<br>(ii) Ph. - E<br>(iii) Ph. - N  | Earth-fault settings may be less than full load.                                                        |
| (h) |                |                |                           | 3Ph. 3w<br>or<br>3Ph. 4w | Ph. - E                                         | Earth-fault settings may be less than full load.                                                        |

Ph. = phase ; w = wire ; E = earth ; N = neutral ; p.o.c. = primary operating current

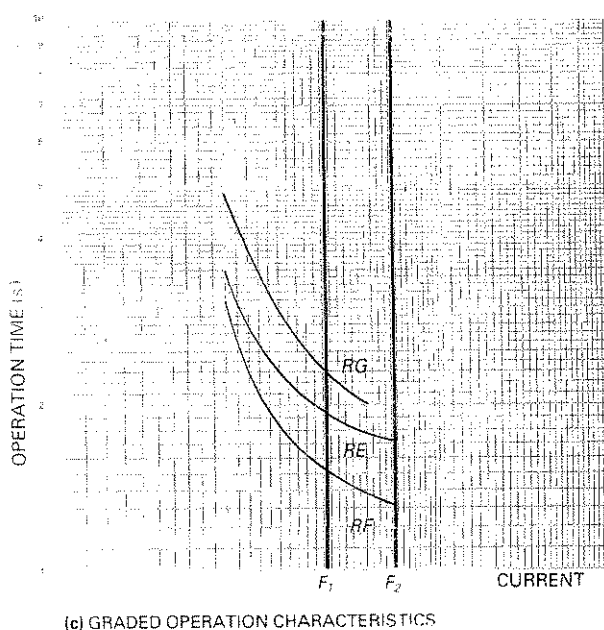
Figure 19.12 Overcurrent and earth fault relay connections.



(a) NEUTRAL BUSBAR ARRANGEMENT.



(b) PROTECTION CIRCUIT DIAGRAM.



(c) GRADED OPERATION CHARACTERISTICS

Figure 19.13 Dual fed four-wire systems: coordination of earth fault protection.

in Figure 19.13(b). This arrangement is suitable for operation with either a normally closed or a normally open bus section breaker. The feeder protection earth fault relay will be fed from either a core balance CT or will be residually fed, using four CTs in the latter arrangement.

When operating with both incoming main circuit breakers and the bus section breaker closed, the bus section breaker must be opened first should an earth fault occur, in order to achieve discrimination or selectivity. It is important to note that relays  $RF$  and  $RE$  will see about twice as much earth fault current as either of the  $RS$  earth fault relays.

The co-ordination time between the earth fault relays  $RF$  and  $RE$  should be established at fault level  $F_2$  for a substation with both main breakers and bus section breaker closed. Similarly the co-ordination time between relay  $RE$  and relays  $RS1$  and  $RS2$  should also be established but at fault level  $F_1$ , as shown in Figure 19.13(c).

When the substation is operated with the bus section switch closed and either one or both incoming supply breakers closed, it is possible for unbalanced neutral current caused by single phase loading to operate relay  $RS1$  and/or  $RS2$  and inadvertently trip one or both supply breakers. This can be prevented by interlocking the trip circuit of each  $RS$  relay with normally closed auxiliary contacts on the bus section breaker.

However, should an earth fault occur on one side of the busbar when  $RS$  relays are already operated, it is possible for a contact race to occur, for when the bus section breaker opens, its break contact may close before the  $RS$  relay trip contact on the unfaulted side can open (reset).

The tripping of both supply breakers may be prevented in this case by raising the pick-up level of relays  $RS1$  and  $RS2$  above the maximum unbalanced neutral current.

If during a busbar earth fault or uncleared feeder earth fault the bus section breaker fails to open when called upon to do so, the interlocking break auxiliary contact will also be inoperative. This will prevent relays  $RS1$  and  $RS2$  from operating and providing back-up protection, with the result that the fault must be cleared eventually by slower phase overcurrent relays. An alternative method of obtaining back-up protection could be to connect a second relay  $RE$ , in series with relay  $RE$ , having an operation time set longer than that of relays  $RS1$  and  $RS2$ . But since the additional relay must be arranged to trip both of the incoming supply breakers, back-up protection would be obtained but busbar selectivity would be lost.

## 19.8

### FAULT CURRENT CONTRIBUTION FROM INDUCTION MOTORS

When an industrial system contains motor loads, it is likely that the motors will contribute current for a short time into any fault which occurs.

This contribution from a motor is often neglected due to lack of guidance. But in view of the greater industrial use of motor drives of increasing power, it is now more often necessary to determine the magnitude and duration of this contribution, so enabling a more accurate assessment of the total effective fault level for:

- Discrimination in relay co-ordination
- Determination of the required circuit breaker rating in a new installation.

When an induction motor is running, a flux, generated by the stator winding, rotates at synchronous speed and interacts with the rotor. If the stator supply voltage is reduced suddenly and severely for any reason, the flux in the motor cannot change instantaneously and the mechanical inertia of the machine will tend to inhibit slowing down over the first few cycles of fault duration. The trapped flux in the rotor generates a stator voltage equal initially to the back e.m.f. induced in the stator before the

fault, the decay of the flux being controlled by the ratio of inductance and resistance of the associated flux and current paths. The induction motor therefore acts as a generator resulting in a contribution of current having both a.c. and d.c. components decaying exponentially as follows:

$$i_{ac} = I_s e^{-t/T_d}$$

$$i_{dc} = 2I_s e^{-t/T_a}$$

where  $I_s$  = direct on line starting current

$T_d$  = a.c. time constant

$T_a$  = d.c. time constant

From various tests taken, it is generally suggested that a composite arbitrary time constant be adopted, derived as follows:

$$T'_d = \frac{X_{ST}}{2f \times R_2(S=0)} \text{ seconds}$$

$$T_a = \frac{X_{ST}}{2f \times R_1} \text{ seconds}$$

where  $X_{ST}$  = Full voltage leakage reactance at standstill

$R_2(S=0)$  = Rotor circuit resistance at zero slip (ohms)

$R_1$  = Stator circuit resistance (ohms)

$f$  = Frequency (Hz)

Arising from tests carried out with industrial motor loads, typical values for  $T'_d$  and  $T_a$  for 415V motors are:

| HP  | $T'_d$ | $T_a$ |
|-----|--------|-------|
| 10  | 20ms   | 10ms  |
| 100 | 50ms   | 40ms  |

Also, currents generated under single phase fault conditions are higher typically than those under three phase fault conditions as shown in Figure 19.14.

It has been shown that the initial a.c. component of current from a motor at the instant of fault is generally of similar magnitude to the direct-on-line starting current of the motor. So on 415V systems 6.25 times motor full load

current is often assumed as the typical fault current contribution. It has also been shown that on a small system all motors can be considered as one equivalent motor, or on large systems several equivalent motors at different locations. The power rating of the single equivalent motor is taken as the sum of the power ratings of the individual motors considered.

A further significant factor is motor speed, since tests have indicated that with motors having less than 6 poles, the fault current contribution takes longer to decay.

In general an assessment of the motor contribution to fault current should be made for large motors and motor loads at 3.3 kV or higher.

Practical values are indicated in Figure 19.15 both for 2 and 4 pole motors and also for slower speed machines. The values are based on the more onerous single phase fault condition and should provide an adequate guide for most practical purposes.

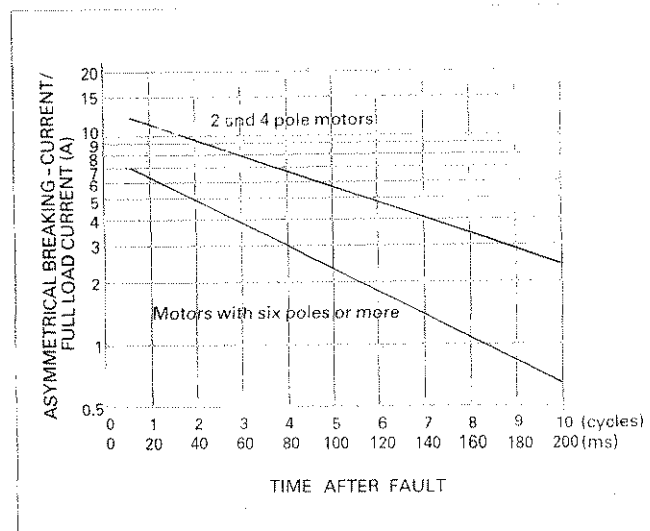


Figure 19.15 Induction motor asymmetrical breaking current contribution.

## 19.9

### AUTOMATIC

Induction motors are being used increasingly to drive critical loads. In some industrial applications, such as those involving the pumping of fluids and gases, this led to the need for a power supply control scheme in which motor and other loads are transferred automatically from a preferred supply to an alternative supply should the preferred supply be lost. A quick changeover enabling the motor load to be re-accelerated reduces the loss of velocity in liquids and the extent of dangerous or undesirable reactions in chemical processes.

When the preferred supply fails, any induction motors connected to that busbar slow down and the trapped rotor flux generates a residual voltage which decays exponentially. The magnitude of this voltage and its phase displacement with respect to the healthy alternative supply voltage is a function of time and speed of the machine. The angular displacement between the motor busbar voltage and the incoming voltage will, at some instant of time be 180°. If the healthy alternative supply is switched on to motors which are running down under these conditions, very high inrush currents may result, producing stresses which could be of sufficient magnitude to cause damage.

If a number of nominally identical motors are connected to the busbar when the healthy supply is lost, they will decelerate at identical rates and no interchange of electrical or mechanical energy will take place.

However, if the motors are not identical, a larger motor with inertia greater than the others will decelerate more

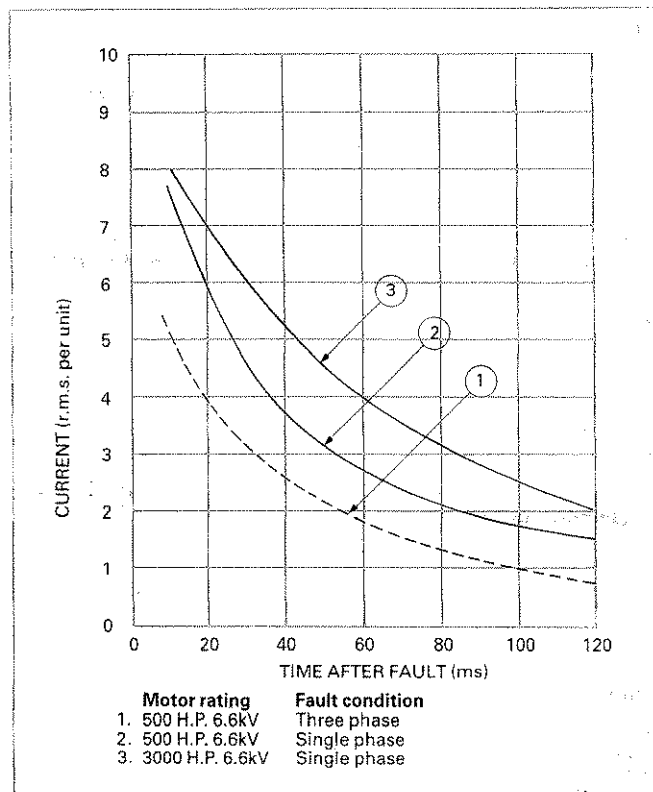


Figure 19.14 Fault current contribution from induction motors.

slowly and as long as its rotor flux remains appreciable will supply energy to the other motors. The result is a tendency for them all to remain 'synchronized' to each other due to the energy transfer between motors, and the residual voltages of all the motors decay at nearly the same rate.

Two main methods of automatic transfer are in use:

- a. In-phase transfer system
- b. Residual voltage system

The in-phase transfer method is illustrated in Figure 19.16(a). Two feeders from the same power source are used, one being the preferred feeder and the other the emergency feeder.

A phase angle relay is used to sense the relative phase angle between the emergency feeder voltage and the motor busbar voltage. When the voltages are approximately in phase, a high speed spring-assisted circuit breaker is used to complete the transfer. This method is restricted to large high inertia drives where the gradual run down characteristic with loss of preferred feeder supply can be predicted accurately.

Figure 19.16(b) illustrates the residual voltage method, which is popular in the petrochemical industry and is more commonly preferred.

Two feeders are used, supplying two busbar sections connected by a normally-open bus section breaker. Each bus section is monitored by an undervoltage residual relay, and should the supply on either feeder be lost, the bus section breaker is not allowed to close to restore the supply until the residual voltage generated by the motors running down on that section falls to a suitable level, between 25% and 40%, dependent on the characteristics of the power system. The choice of residual voltage setting will influence

the re-acceleration current after the bus section breaker closes. For example, a setting of 25% may be expected to result in an inrush current of around 125% of the starting current at full voltage.

It is of course, essential that both feeders are capable of carrying the standing load on their own section, together with the additional load imposed when the bus section breaker closes, including the enhanced load during the re-acceleration period.

When an induction motor runs down, not only is the magnitude of the residual voltage reduced, but also the frequency. The residual undervoltage relay must therefore have a voltage characteristic independent of frequency. A rectified moving coil relay such as the type DBA4 is particularly suitable for this residual undervoltage application.

## 19.10

### VOLTAGE AND PHASE REVERSAL PROTECTION

Voltage relays are widely used in most industrial power supply systems. Sometimes they are of the overvoltage type, but more usually of the undervoltage type, particularly with systems involving motor drives. The mechanical load on an induction motor will cause the current drawn from the power supply to increase when the supply voltage falls. But the undervoltage protection must operate to switch off the supply before the load current increases to a level which would cause dangerous overheating.

If a motor is started when the voltage is low the starting time of the machine will be extended, sometimes to an unacceptable level, particularly when the low voltage is reduced even further by the starting current inrush. So undervoltage relays are often used as starter interlocks to prevent start initiation on reduced supply voltage.

Undervoltage relays are sometimes applied in the mistaken belief that they will detect a single phasing condition. Such detection may well be possible if the load is mainly resistive, but if motoring load is present in sufficient amount, the voltage may be held up in the open circuited phase to between 60% and 90% of the nominal voltage, making the detection of single phasing by undervoltage measurement unreliable.

In any situation where voltage protection relays are employed, it is advisable also to apply a timing relay to prevent operation on transient disturbances.

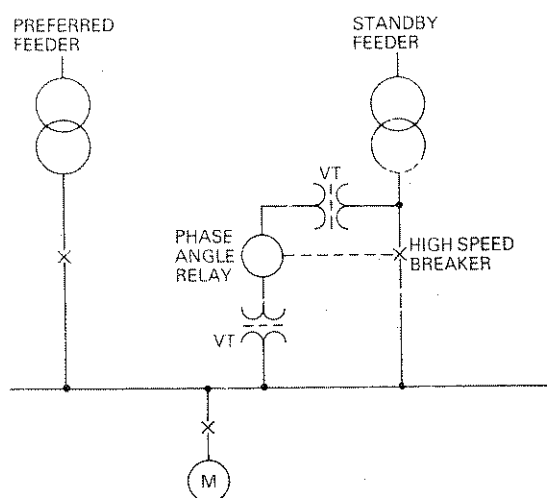
When determining voltage relay settings it is also important that the drop-off/pick-up ratio of the relay be considered, since once operated it must be possible for the relay to reset when the normal voltage has been restored.

With many systems, especially those involving motor drives, protection is required against reverse phase sequence which would result in reverse rotation and possible damage.

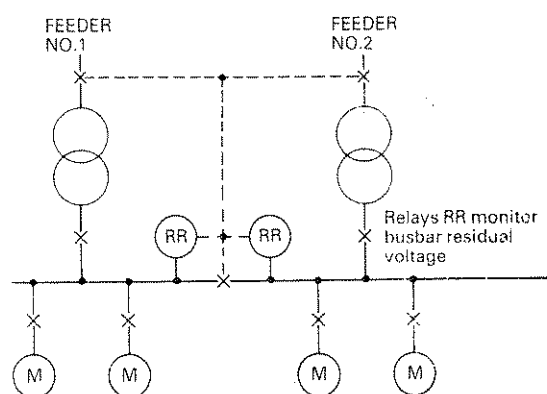
Where motors are protected by a motor protection relay capable of distinguishing the sequence components of the current, reverse phase sequence as well as single phasing protection is inherently given by the negative sequence circuits of the relay.

Where such relays are not present a relay designed specifically for reverse phase sequence protection may be applied. An example of this type is the VDM relay which is an induction disc relay giving combined, adjustable inverse time undervoltage protection, with a high drop-off/pick-up setting ratio, as well as reverse phase sequence protection. An auxiliary output element is included to provide contacts for direct tripping, interlocking and alarm purposes.

Illustrated in Figure 19.17 is a typical motor panel application, to prevent starting with abnormally low voltage, reverse phase sequence, or with an open circuit on one phase of the supply.



(a) IN PHASE TRANSFER METHOD.



(b) RESIDUAL VOLTAGE METHOD.

Figure 19.16 Auto-transfer systems.

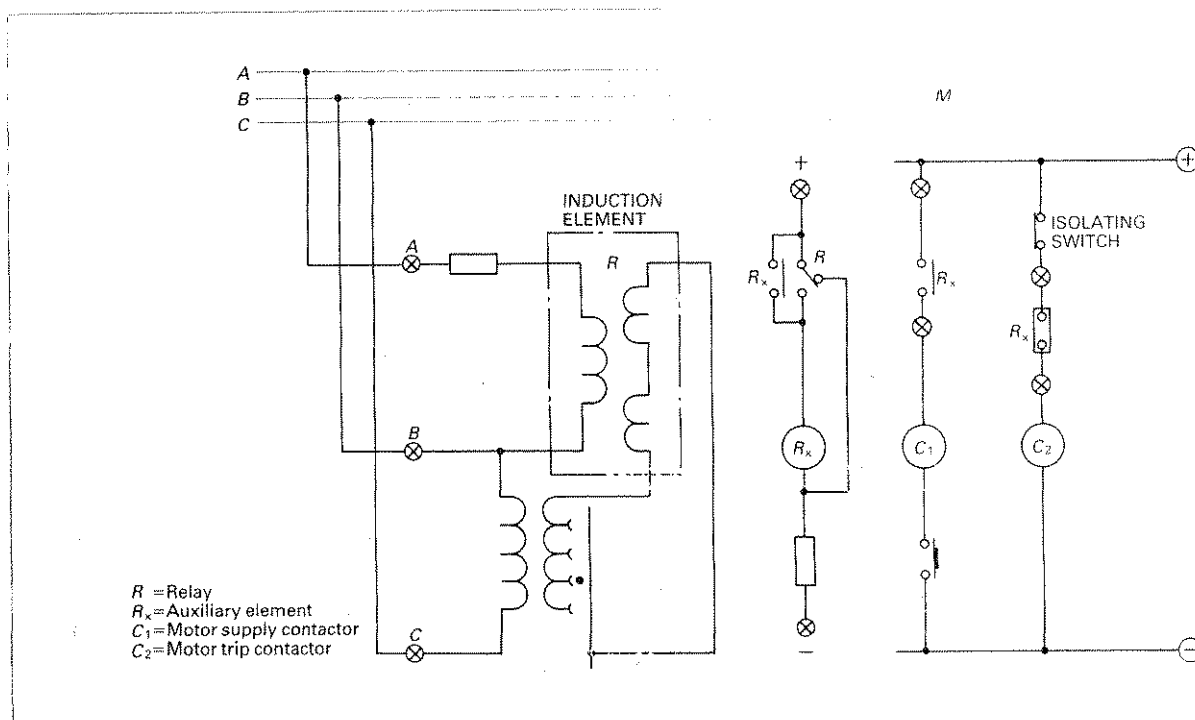


Figure 19.17 Reverse phase sequence and undervoltage relay type VDM.

## 19.11 FEEDER PROTECTION

Some industrial power supply systems make extensive use of cable feeders, for example between an HV breaker and a transformer, or between the substation and the plant room or remote areas of the site. These feeders can usually be protected conveniently by some form of unit protection.

'Unit protection' is the method whereby sections of a power system are protected individually without reference to any other sections, and is described fully in Chapter 10. The unit protection probably best suited to industrial applications is feeder differential protection of the pilot wire type. This employs a relay at each end of the protected feeder, information being conveyed between them by means of light cables, normally 2.5 mm<sup>2</sup> known as 'pilots'.

A very well established differential feeder protection is the electromechanical 'Translay' system described in Chapter 10, which uses induction disc relays with inbuilt transformer action and works on the voltage balance principle with a low pilot current.

A static version using the circulating current principle and known as 'Translay S' is also available. This is modular, more sensitive and has optional modules for pilot wire supervision and for intertripping.

## 19.12 INDUSTRIAL POWER TRANSFORMERS

All the types of protection appropriate to the power transformers in the substations of the larger industrial or commercial organizations have been covered in Chapter 16. However, for economical reasons it is usual that only the simplest forms of protection are applied, such as the oil pressure devices, Buchholz relays, inverse time overcurrent and instantaneous restricted earth fault relays.

Unit protection schemes, such as biased overall differential protection, are not usually applied in such instances for power transformers rated below 1 MVA.

In general, no sophisticated forms of protection are applied to industrial power transformers rated below 1 MVA, unless they are in 'hazardous areas' such as department stores. Here the demarcation level may be 315 kVA or 500 kVA and on rare occasions as low as 200 kVA.

## 19.13 SYNCHRONISM

Synchronous motors are often used in industrial applications, for such as compressors, pump or mill drives and elsewhere when constant speed or power factor correction is required. The latter is a useful bonus and is obtained by control of the excitation level of the motor. Increase in excitation, beyond that required to maintain a particular load at unity power factor, results in leading power factor operation and therefore a measure of compensation can be applied to the localized power system as a whole. A salient pole rotor construction is usual for the majority of synchronous motors, the rotor field circuit being energized by a d.c. source obtained either from a d.c. exciter unit on the motor shaft, or from a static thyristor power supply.

Occasionally when a synchronous drive is required to have high starting torque, a different type of construction similar to that of a slip ring motor is used. The starting method is also similar, with run up by inserting rotor circuit resistance in the rotor circuit and then progressively removing it as the machine gathers speed. D.c. excitation is then applied to pull the machine into synchronism. This type of machine is known as the 'synchronous induction motor'.

The a.c. motor protection principles detailed in Chapter 20 apply generally for synchronous motors, with the addition of protection made necessary by the presence of the d.c. excitation.

With synchronous motors of salient pole construction, the inductance of the rotor field circuit is liable to cause high transient overvoltages on disconnection. To prevent this a field discharge resistor is switched across the field by a normally closed contact of the d.c. excitation circuit breaker, the contact having 'make before break' action to ensure application of the discharge resistor before excitation is removed by the opening of the breaker main poles.

This type of motor is usually started by running it up to speed as an induction motor, with a squirrel cage winding, embedded in the pole faces of the rotor, assisting the process.

When approaching synchronous speed the d.c. field supply must be applied at the right moment in time to pull the motor into synchronism. Often difficulty is experienced with this, especially if the machine is trying to pull into



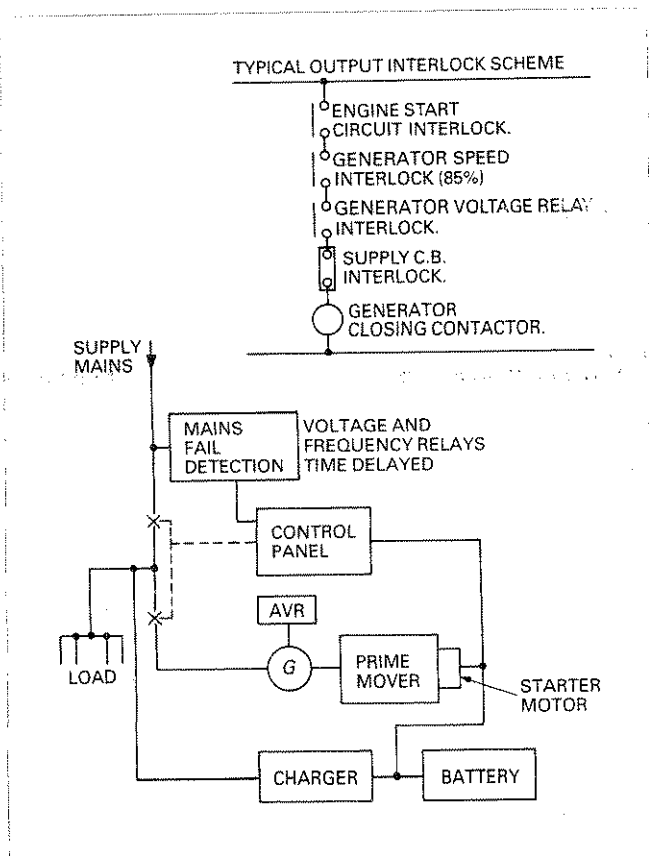


Figure 19.19 Mains failure standby set.

relays suitably time delayed to prevent unnecessary operation on supply transients.

Deviation of the mains supply outside preset operating limits initiates starting of the set, via the control panel, followed by the tripping of the supply breaker and when the generator speed and voltage interlocks operate, and the closing of the generator breaker to take over the load. The whole operation usually takes about 12 seconds.

Restoration of the load to the mains supply, when the latter is eventually available and within limits, may be performed either manually or automatically using a restoration timer with long adjustable delay.

In addition to the control devices, the control panel contains the necessary protective relays for the generator, according to the size of the machine.

#### 19.14.2 Prime movers

With industrial generation, three main types of prime mover are in use:

##### i. Steam turbines

Usually encountered in large base load systems or in standby systems in industries where waste steam is available.

##### ii. Gas turbines

Often used in peak loading and mobile power plant applications.

##### iii. Diesel engines

The most popular industrial generation prime mover, often used on standby systems.

#### 19.14.3 Industrial generator protection

Since industrial generation plays such an important part in the maintenance of supply to essential services in industrial power systems, it is of the utmost importance that every effort should be made to reduce the possibility of fault damage to the generating plant and thereby to maximize its

availability. The degree of protection to be provided to an industrial generator will vary considerably depending on the size, type of plant, and physical layout. The main points to bear in mind when making a choice are the method of earthing, the magnitude of the prospective fault current as a percentage of the full load rating of the machine, and whether the generator is to be operated singly or in parallel with other machines.

For sets of 1 MW rating and above it is usual for a comprehensive scheme of protection to be used, such as that illustrated in Figure 19.20 which shows a typical protection system for a generator operating on its own, and feeding directly into the distribution system. With this type of arrangement no difficulty is experienced in providing adequate protection against stator earth faults regardless of the type of system earthing used, and a popular, simple arrangement is to use a current transformer in the earth connection of the earthing resistor in combination with an inverse time earth fault relay. The current setting of the earth fault relay is chosen to coordinate with the protective devices on the outgoing feeder circuits.

For many years electromechanical relays have played the major part in the protection of generating plant, but with the advent of the new technology these are gradually being replaced by more compact and more sensitive solid state relays.

The MIDOS package for the protection of industrial generators shown in Figure 19.21 is typical of this trend. It is available for rack or panel mounting, with all the interconnecting wiring being carried out in the factory during the assembly stage, and with the only wiring required on site being the inputs from the appropriate CTs and VTs and the tripping, alarm and indicator circuits.

The number and combination of relay modules used in a

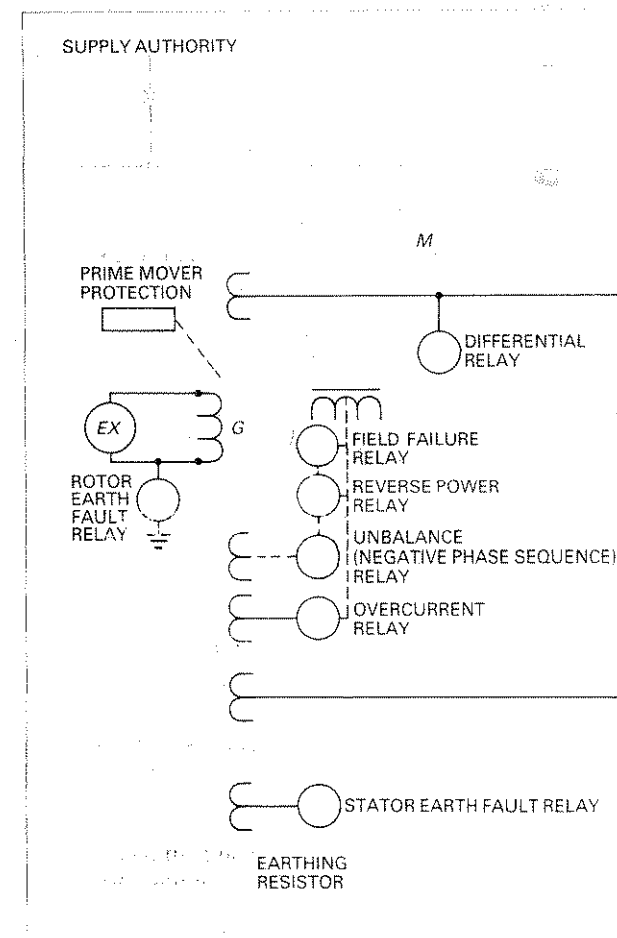
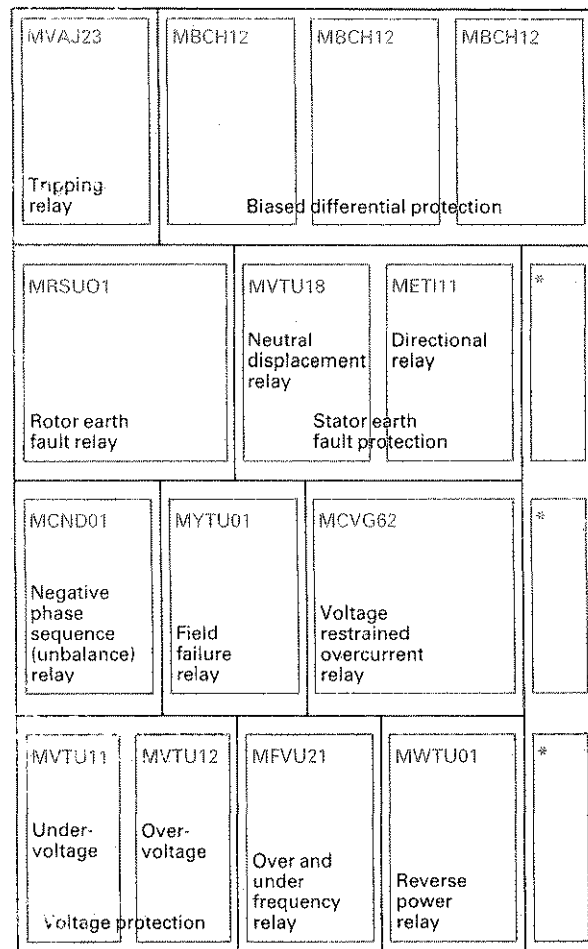
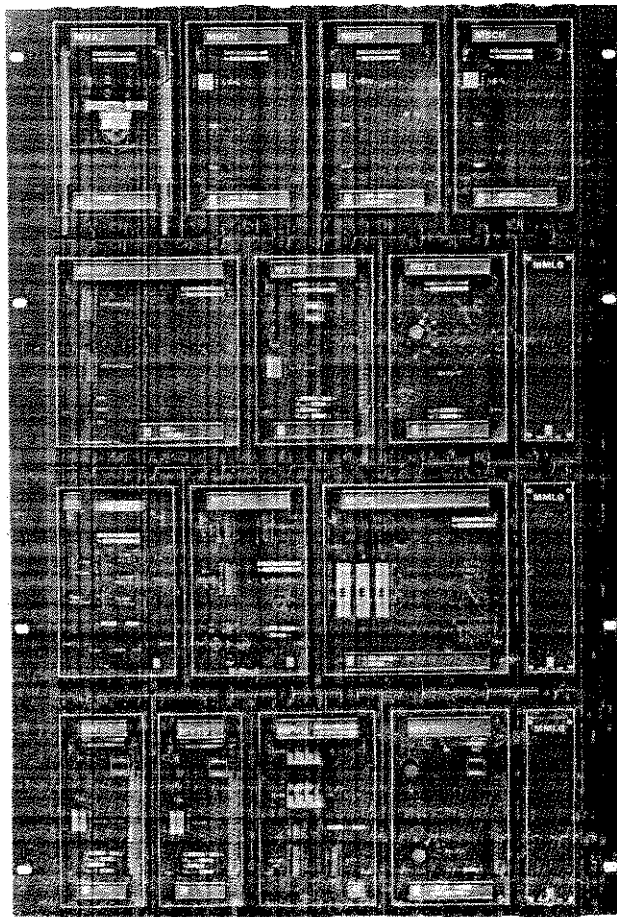


Figure 19.20 Protection of industrial generator, operating on its own.



\*MMLG01 Test block

Figure 19.21 MIDOS generator protection package for machines operating in parallel.

package can be altered to suit the application and the degree of protection required to meet the particular system requirements of the various prime movers used with generators in industrial power systems.

The package shown in Figure 19.21 is suitable for a generator operating in parallel with other machines, where each generator is earthed via an earthing resistor which limits the maximum earth fault current on each generator to a value below the earth fault sensitivity of the generator biased differential relay. In such an arrangement the earthing resistor is shunted by a single phase voltage transformer in order to provide the polarizing voltage for the directional earth fault relay, used to achieve the required discrimination between the various machines for stator earth faults, and to operate a neutral displacement relay which serves the dual role of providing a time delayed trip for the directional earth fault relay and back-up protection to the generator and the distribution system.

A detailed description of generator protection is given in Chapter 17, but a summary of the principal items applicable to industrial generators is offered here.

The method of generator earthing is very important, since high fault current can cause considerable machine damage. Small 415 volt generators are usually solidly earthed, but larger and higher voltage generators are usually resistance earthed as shown, or earthed using a distribution type transformer to limit the possible earth fault current to a very low value.

The stator earth fault protection relay shown will usually be of the I.D.M.T. type. With the single CT connection the protection is unrestricted and will require to have settings co-ordinated with those of other earth fault protection relays on the system.

If an earth fault occurs on the rotor circuit of a generator, output will not immediately be impaired, however the occurrence of a second fault is most likely to result in serious electrical and also possibly, mechanical disturbance to the generator system.

If the rotor system is not of the brushless configuration, earth fault protection can be given by an injection type relay giving an alarm.

For many years generator excitation was obtained exclusively from rotating d.c. exciters, and a sensitive yet relatively simple relay, such as the type VME could be suitably applied to detect rotor earth faults. Nowadays many excitation systems are derived from static thyristor sources with higher harmonic content and for this type of excitation, a moving coil relay such as the type DBAE is generally more suitable.

Differential protection is applied to the generator to give instantaneous phase and earth fault protection of the stator winding, for simplicity with a relay of the high impedance type.

Overcurrent relays of the I.D.M.T. type, voltage controlled or voltage restrained, are usually applied to generators as a general protection back-up feature. The operation characteristics of these relays are not related to the thermal withstand characteristic of the generator as they are intended to operate only under fault conditions.

#### 19.14.4

##### Unbalanced loading

An industrial load may well be phase unbalanced, and while operation from the public supply may be satisfactory under such conditions, it is important to ensure that any



industrial generator used can cope with the degree of load unbalance it may be called upon to supply.

Unbalanced load on a generator gives rise to stator negative sequence currents (current acting against normal phase rotation), inducing double frequency currents in the rotor and increasing machine heating. Manufacturers give machine ratings in terms of both the continuous negative sequence current withstand ( $I_2$ ) and also the short time withstand ( $I_2^2 t$ ).

Salient pole machines, particularly those with laminated poles and heavy damper windings, have a fairly high rating and may not need unbalance protection, but generators on larger turbine drives may have a cylindrical type rotor with a low rating and would normally require unbalance protection.

#### 19.14.5 Reverse power

Reverse power protection is applicable to the parallel operation of generators, to protect against prime mover failure. This may allow the generator to take power from the system and so motor the mechanical drive, possibly resulting in damage to an extent which will vary dependent upon the type of prime mover.

It is important that each application is considered individually with data on the maximum permissible levels of motoring power obtained, if necessary, from the generator set manufacturers.

The protection applied is usually of the wattmetric type, set below the safe reverse power withstand level of the whole drive. Since motoring power is a balanced load, it is sufficient to apply the reverse power relay to one phase only.

#### 19.14.6 Industrial generation and motor starting

A problem area often associated with industrial generation concerns motor starting, in particular when a standby generator is connected to the system following a mains failure. The connected motor loads must be restarted, but difficulty may be experienced because of:

- fall in voltage
- lack of prime mover power
- a combination of (a) and (b)

Dealing firstly with fall in voltage, it is usually a precondition for the generator to have attained normal voltage and speed before the associated control circuit interlocks enable the generator breaker to close.

The motors not disconnected by undervoltage devices responding to mains failure, together with other standing

loads, will be energized immediately upon breaker closure, possibly resulting in a voltage 'dip'. Unfortunately, with induction motors, the torque varies as the square of the voltage and since the motor accelerating torque will drop appreciably as the motor voltage dips, starting time may be extended considerably, possibly even in excess of the  $I^2 t$  withstand limit of the motor. Figure 19.22 illustrates the effect of voltage variations on typical induction motor characteristics.

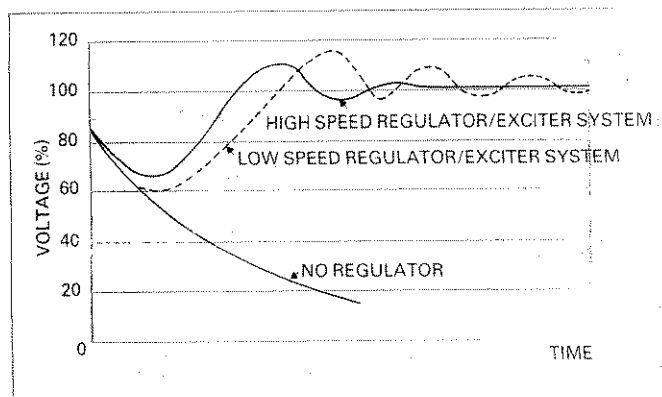


Figure 19.23 Effect on generator terminal voltage of exciter/regulator system.

The magnitude of the voltage dip will depend upon several factors, one being the source impedance which in the case of an industrial generator is usually high in comparison to that of the public supply. Another important item is the generator excitation system, since the type of voltage regulator applied can have a significant influence, as illustrated in Figure 19.23.

Another influence is the power factor of the motor starting load, typical values being:

- for motors of up to 1000 HP rating, power factor = 0.2
- for motors over 1000 HP, power factor = 0.15

The power factor determines the amount of reactive power drawn from the system and therefore to a large extent, the maximum voltage drop.

In general, during motor starting, the voltage level at the motor terminals should be maintained to at least 80% of the nominal voltage.

Regarding the power available to meet the connected load requirement, this is often limited by the governor and fuel system of the prime mover, the preset maximum available being capable of supporting a load of about 110% full load. Also, with some prime movers the maximum engine power may not be available immediately the generator breaker closes and this must be taken into consideration also.

A further problem may arise when a load is already being supplied by the generator and an additional motor starting load is switched on. The power available in this case must be sufficient both to support the full connected load, and to provide the additional power necessary to accelerate the motor load up to full speed.

Most difficulties involving industrial generators and motor starting are resolved by segregating the loads and reclosing them in stages at time intervals. More difficult cases may also require adoption of assisted starting methods such as auto-transformer starting for certain motors.

#### 19.14.7 Load shedding

If the amount of load connected to a generator continues to be increased above its full load rating, then eventually the regulating systems associated with the generator set will be unable to compensate and emergency measures will be necessary to ensure the continuity of supply. Usually this is accomplished by means of a load shedding

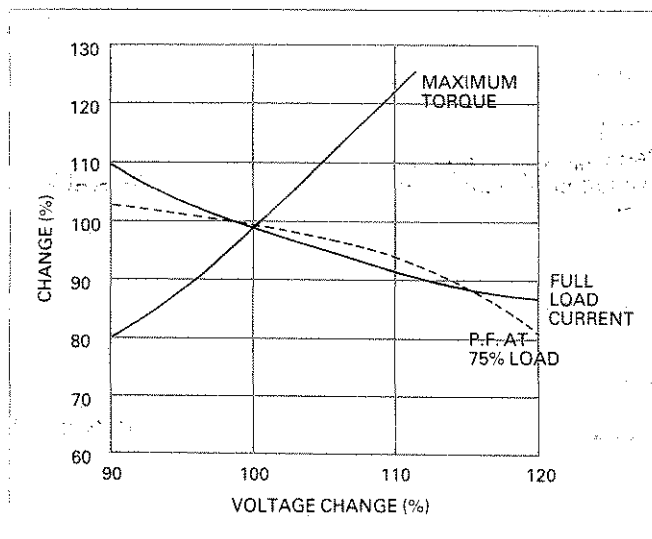


Figure 19.22 Effect of voltage variation on induction motor.

operation, in one of the following two ways:

- a. voltage reduction
- b. disconnection of low priority loads

Reduction in voltage is effective only when the amount of connected motor load is low. With most industrial systems, motor load accounts for a high proportion of the total load, and since a motor draws more current when terminal voltage falls, load shedding on an industrial system by means of voltage reduction is sometimes ineffective. Disconnection of loads is more effective, so loads of lower priority are often arranged in one or more groups, each fed from a breaker arranged to be tripped when required.

The generator load capability is determined by the prime mover and its fuel system. Therefore when the load is increased above the generator rating, the speed governor eventually can no longer correct the generator speed and the frequency will commence to fall. An underfrequency relay, suitably time delayed, may be applied to detect this situation and to initiate load shedding.

One or two stages are usual, each with its own under-frequency relay and time delay.

Large systems often use two relays. For example, on a 50 Hz system one would be set at around 48 Hz and arranged to trip the 'low priority' loads and a further relay would be set at 47 Hz or above, with time delay and arranged to trip either all of the load, or sufficient 'higher priority' load to ensure security of generator supply to the 'top priority' load remaining connected.

The settings of the frequency and time delay relays will be determined to suit the characteristics of the load and also those of the generator set.

Another example of where load shedding may be required concerns industrial standby generator sets where the prime mover is of the diesel type. This prime mover is available in both 'naturally aspirated' and 'turbo-charged' versions with the 'naturally aspirated' type usually capable of accepting full load immediately it is up to speed.

The 'turbo-charged' version, however, has the advantage of increased power for a particular size, owing to the power contribution from the turbo-charger, but suffers from the disadvantage that turbo-charger power contribution depends upon exhaust temperature. Full rated power is therefore not available when the engine first reaches full speed. Instead, only 70% to 80% is immediately available and the remaining power is produced later when the rise of exhaust temperature enables the turbo-charger to make its full contribution.

Because of this characteristic, a load shedding scheme is necessary in many mains-failure standby schemes employing turbo-charged diesel engines. Sufficient non-essential load is shed immediately upon mains failure and may not be reconnected until the mains supply has been fully restored. Alternatively it might be connected automatically to the generator supply by time delay relays, at intervals, commensurate with the available engine power.

#### 19.14.8

##### Synchronizing

Before a generator is connected to live busbars energized from either another generator or any other supply, precautions must be taken if possible damage and supply disruption is to be avoided. The conditions to be met are:

- a. The magnitude of the incoming generator voltage must be equal to that of the busbar voltage.
- b. The incoming generator voltage must be in phase with busbar voltage.
- c. The frequency of incoming generator voltage must match that of the busbar voltage.

The process of obtaining the above conditions simultaneously is known as synchronizing and may be performed automatically or manually as follows:

##### i. Automatic synchronizing

The automatic synchronizing unit not only senses when the correct conditions have been met but also produces correction signals to operate servomotors in the voltage and speed regulating systems of the incoming supply. Circuit breaker closing-time compensation is also often included in the operating sequence.

For prime movers fitted with certain types of electronic governors, synchronizing units are available giving correction signals direct into a proportional fuel actuator, so obtaining quick synchronizing.

##### ii. Manual synchronizing

In this arrangement adjustments are carried out manually to produce the correct incoming conditions. The optimum moment for synchronizing by closing the circuit breaker manually is determined by observation of a synchroscope and lamps.

##### iii. Check synchronizing

Manual synchronizing is often supported by use of a check synchronizing unit. This unit is not intended to be a fully automatic synchronizer, but is used to inhibit the circuit breaker closing circuit until the approach of the correct synchronizing conditions. The breaker is then closed manually when the synchroscope indicates the correct moment.

#### 19.14.9

##### Parallel operation with supply authority network

For a considerable time some power authorities have permitted the occasional parallel operation of suitable private generation with their supply system for purposes such as 'peak lopping' and plant change-over. These applications involve only short-time parallel operation and the presence of suitable reverse power protection to prevent the export of power from the private generator into the electricity authority's supply system is usually obligatory.

The growth of private generation has now resulted in some schemes where it may be of economic advantage if export of power into the authority's supply system is permitted. However, in many areas this has been prevented to date by power supply regulations, but legislation has now been enacted in many countries to permit this mode of operation.

When private generation is permitted to operate on a long-term basis in parallel with the authority's supply, such plant virtually becomes an extension of the authority's supply system. As power supply authorities have a legal obligation regarding the safety and also the quality of the electricity supply to consumers, they consequently impose strict conditions relating to the design, application and operation of the plant.

When considering generating plant for this type of operation, many aspects require careful assessment to ensure complete suitability.

The generator prime mover must be equipped with governing equipment properly designed for infinite bus operation. The generator must also be provided with adequate automatic voltage and power factor control. A further point, often overlooked, is that certain generator/prime mover combinations produce cyclic variations in output which may not be acceptable to the power authority.

Generator harmonics may present a further problem, though most rotating generators designed to national standards will have low and compatible harmonic levels. However, some generators and, in particular, many static inverter systems produce harmonic levels of unacceptable magnitude.

System earthing is also a very important item, and the type of earthing required for the generator system will be specified by the power authority.

Operation of the generating plant may cause variations on

the authority's supply, as an export of power from the generator into the authority's network will tend to cause a voltage rise at the point of connection, possibly affecting other local consumers.

In addition to accurate metering, the power authority will also require adequate protection to be installed, including such as over- and undervoltage protection, over- and underfrequency protection, circulating current differential protection, and also possibly maximum power limitation. This sometimes comprises a two-stage arrangement, with the first stage giving an alarm and initiating power reduction, and the second stage causing disconnection and shut-down of the generator if excessive power output persists.

The above indicates only some of the points involved. So when considering parallel operation with the local electricity authority's supply system, it is clearly advantageous to make contact and have discussion with the power authority at the earliest possible stage.

### 19.15 POWER FACTOR CORRECTION AND PROTECTION OF CAPACITORS

Items of load such as transformers, reactors and motors have one thing in common, they are inductive loads and draw lagging magnetizing current from the circuit, resulting in a situation in which not all of the current supplied to the circuit is effective in producing power. Only the current component in phase with the voltage is effective in this. A ratio which indicates this effectiveness and is known as the power factor corresponds to:

$$\frac{\text{Current effectively used}}{\text{Current supplied}} \text{ or } \frac{\text{Kilowatts (kW)}}{\text{Kilovoltamperes (kVA)}}$$

For example, with a power factor of 0.5 for a given kW loading, the current in the supply cables is twice the value it would be at unity power factor. The higher current level increases the voltage-drop losses in the system and the variation of voltage-drop with power factor on a typical loaded 300 kVA transformer is shown as an example in Figure 19.24.

The problems relating to the higher currents resulting from low power factors are also the concern of the power supply authorities, who commonly penalize consumers having low power factor systems, by means of the tariff charged for the supply of power.

The industrial consumer is thereby induced to improve the power factor of his system and may install power factor correction equipment to restore the effective power factor at the power input point to unity or near unity.

Capacitors play an important part in such power factor correction schemes because they draw current which leads the supply voltage when they are energized from an a.c. source. Since inductive loads draw lagging currents, the capacitance current may be used to compensate for them. The lagging or leading components of current are said to be 'reactive', and the reactive component is measured in kilovars (kVARs). Power factor correction is achieved by introducing sufficient capacitive leading kVAR to compensate, with definable accuracy, for some of the lagging kVAR of the plant installed, so reducing the kVA demand on the system.

The basis of this compensation is illustrated in Figure 19.25 where  $\phi_1$  represents the existing uncorrected angle of lag and  $\phi_2$  the angle relating to the desired power factor after correction. The following may be deduced from this vector diagram:

$$\text{Uncorrected power factor} = \frac{\text{kW}}{\text{kVA}_1} = \cos \phi_1$$

$$\text{Corrected power factor} = \frac{\text{kW}}{\text{kVA}_2} = \cos \phi_2$$

$$\text{Reduction in kVA} = \text{kVA}_1 - \text{kVA}_2$$

If the kW load and uncorrected power factors are known, then the capacitor rating in kVAR to achieve a given degree of correction may be calculated from:

$$\text{Capacitor kVAR} = \text{kW}(\tan \phi_1 - \tan \phi_2)$$

In practice it is generally simpler to use a nomogram such as that shown in Figure 19.26 which relates the  $\cos \phi$  values with the  $\tan \phi$  values.

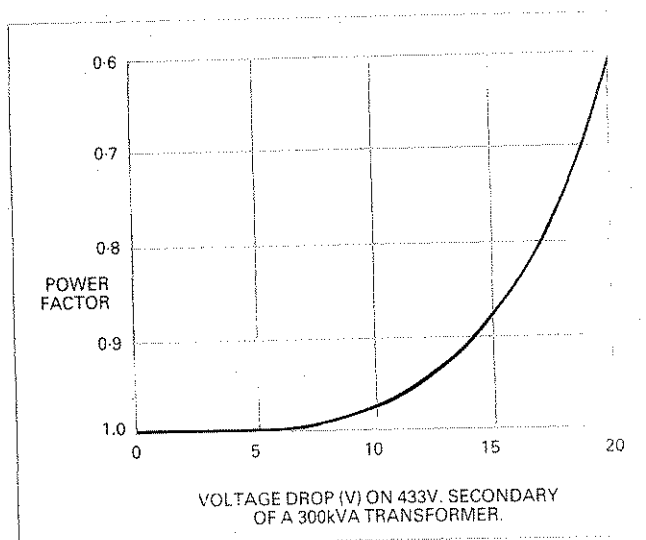


Figure 19.24 Variation of voltage drop with power factor.

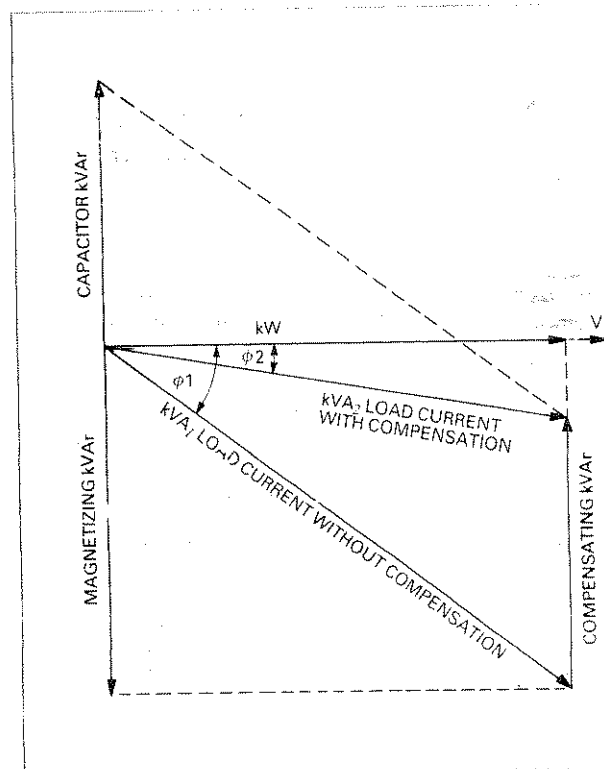
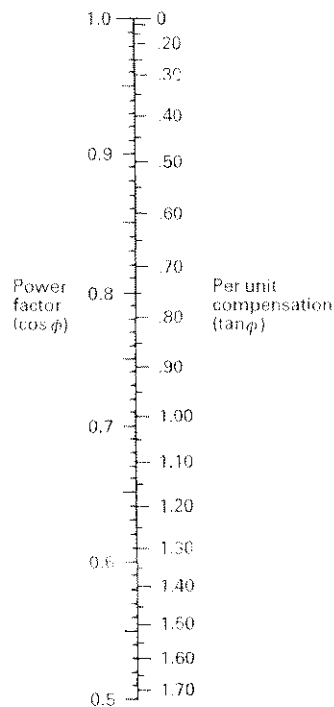


Figure 19.25 Power factor correction principle.

#### 19.15.1 Capacitor construction and control

A typical capacitor for medium voltage industrial use has comprised a number of flat elements consisting of aluminium foil interleaved with high grade tissue paper impregnated with a synthetic liquid. The elements are assembled lightly compressed in a three-phase pack and contained in a welded steel box, which is hermetically sealed. A discharge device is fitted to reduce the voltage quickly after disconnection from the supply. Nowadays



Example: To improve the power factor of a 100 kW load from 0.7 to 0.9:

$$\begin{aligned} \text{Required kVAR} &= 100 (1.02 - 0.48) \\ &= 54 \end{aligned}$$

Figure 19.26 Compensation nomogram

these capacitors are more likely to be constructed from metallized plastic film.

In general, capacitors of up to 4.5 MVAR rating and for use on systems rated up to 11 kV are delta connected.

In some industrial systems capacitors are switched in manually when required, but automatic controllers are more often used for this. Typical of a modern controller is the 'NOVAR' capacitor controller, which is a static circuit device providing automatic power factor correction for three phase systems, by detecting the leading or lagging voltamperes above a preset level. The appropriate amount of capacitance is then switched 'in' or 'out' to achieve the best average power factor. The controller is fitted with a 'loss of voltage' element to ensure that in the event of a power interruption, all selected capacitors are disconnected instantaneously. When the supply voltage is restored, the capacitors are reconnected progressively in sequence, so avoiding the large transient currents which would otherwise be caused by restoring the supply simultaneously to a large bank of uncharged capacitors.

### 19.15.2 Motor correction

When dealing with power factor correction of motor loads, group correction is not always the most economical method. So some industrial consumers apply capacitors to selected distribution centres rather than apply all of the correction at the substation busbars.

Often individual correction is applied directly to certain motors, resulting in optimum motor power factor being obtained under all conditions of motor load. In some instances, better motor starting may also result, from the improvement in the voltage regulation due to the capacitor.

Motor capacitors are often six terminal units, and a capacitor may be conveniently connected directly across each motor phase winding. Where three terminal

capacitors are used with star/delta motor starters, the capacitor should be connected across motor terminals  $A_2$ ,  $B_2$  and  $C_2$  to obtain the required correction.

Selection of capacitor size is important and should be such that a leading power factor is not obtained under any load condition.

If excess capacitance is applied to a motor it may be possible for self-excitation to occur when the motor is switched off or suffers a supply failure. This can result in the production of a high voltage, or in mechanical damage if there is a sudden restoration of supply.

Since most star/delta or auto-transformer starters other than the 'Wauchope' or 'Korndorfer' types involve a transitional break in supply, it is generally recommended that the capacitor rating should not exceed 85% of the motor magnetizing VAR.

### 19.15.3 Capacitor protection

When considering protection for capacitors, allowance should be made for the transient inrush current occurring on switch-on, since this can reach peak values of around 20 times normal current. (Switchgear for use with capacitors is usually derated considerably to allow for this).

A further possibility requiring consideration is the presence of harmonics in the supply voltage which would increase the capacitor current.

Protection equipment is required to prevent rupture of the capacitor due to an internal fault and also to protect the cables and associated equipment from damage in the event of a capacitor failure. If fuse protection is contemplated for a three phase capacitor, HRC fuses should be employed with a current rating of not less than 1.5 times the rated capacitor current.

When relay protection is applied to a medium voltage capacitor, an I.D.M.T. overcurrent relay with two phase fault and one earth fault elements is usual, together with high set instantaneous overcurrent elements, as shown in Figure 19.27. Since harmonics increase capacitor current, the relay will respond more correctly if it does not have inbuilt tuning for harmonic rejection.

Suitable relays are the electromechanical relay type CDG51 with high performance instantaneous elements type CAG19, or the 'MIDOS' static relay type MCGG.

Some industrial loads such as arc furnaces involve large inductive components and correction is often applied using very large high voltage capacitors in various configurations.

When double star capacitor banks are employed, as shown in Figure 19.28, a current transformer in the common

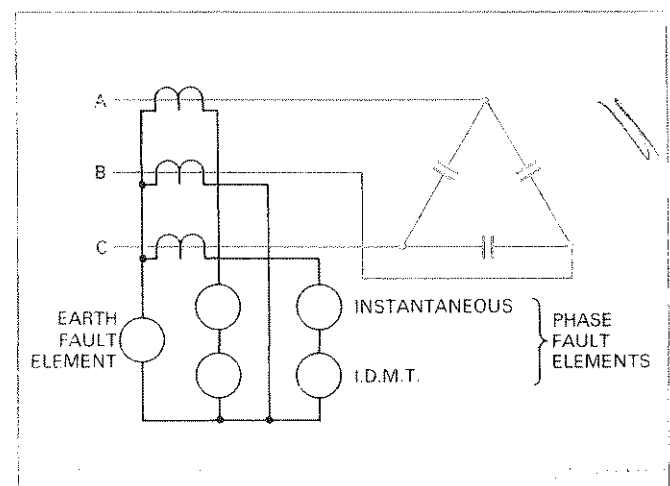


Figure 19.27 Overcurrent and earth fault protection of capacitors.

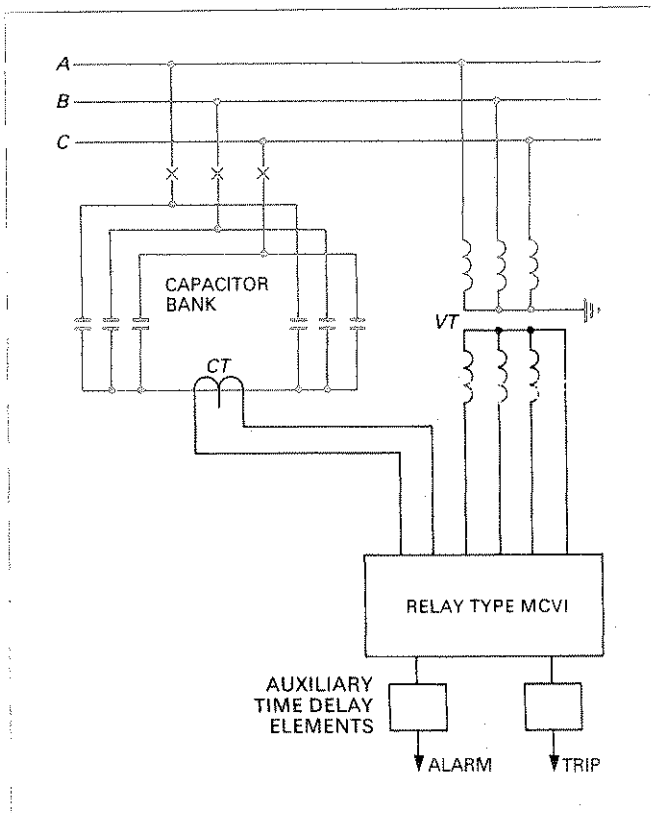


Figure 19.28 Protection of double star capacitor banks.

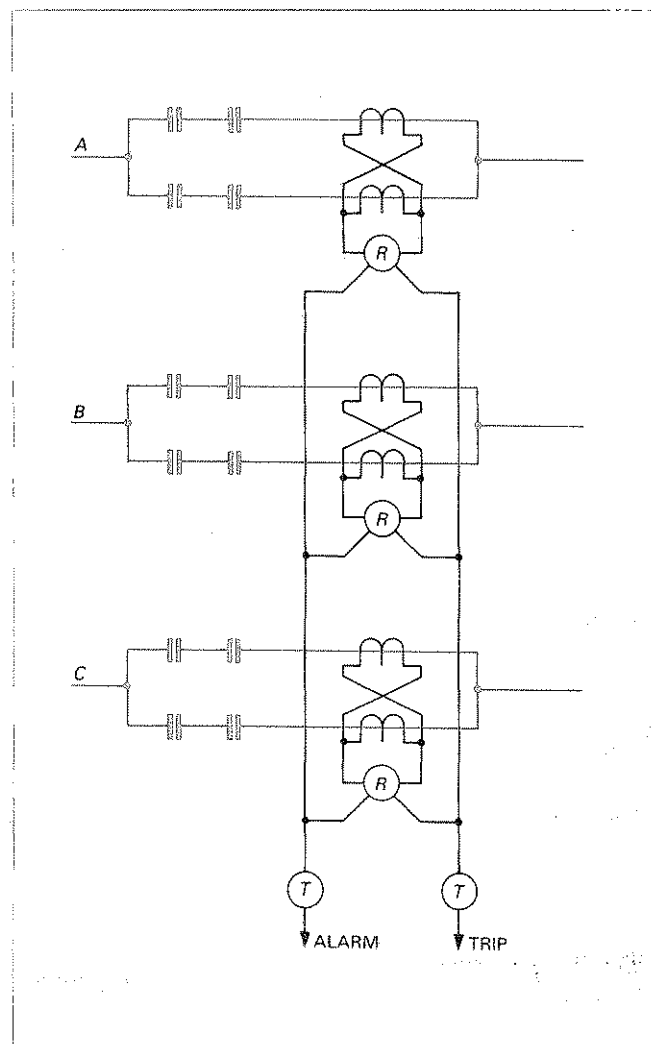


Figure 19.29 Differential protection of split phase capacitor banks.

neutral can be used to enable a protection relay to detect the out-of-balance currents which will flow when capacitor elements become short-circuited or open-circuited. The relay will have adjustable current settings, and may contain a bias circuit fed from an external voltage transformer to compensate for the healthy state spill current in the neutral.

Another high voltage capacitor configuration is the 'split phase' arrangement where the elements making up each phase of the capacitor are split into two parallel paths. Here a differential relay can be applied, fed from a current transformer in each parallel branch, as shown in Figure 19.29.

The relay compares the current differentially in the split phases, with sensitive current settings but also adjustable compensation for the unbalance currents arising from initial capacitor mismatch.

# A.c. motor protection

- 20.1 Introduction
- 20.2 Bearing failures
- 20.3 Heating of motor windings
- 20.4 Overload protection
- 20.5 Motor currents during starting and stalling conditions
- 20.6 Stalling of motors
- 20.7 Operation of three-phase induction machine on unbalanced supply voltages
- 20.8 Determination of sequence currents
- 20.9 De-rating of machine due to unbalanced currents
- 20.10 Stator protection
- 20.11 Rotor protection
- 20.12 Single-phase overcurrent relays
- 20.13 Phase unbalance relay
- 20.14 Electrical faults in motor windings
- 20.15 Faults in rotor windings
- 20.16 Modern relay design
- 20.17 Additional protection for synchronous motors

## 20.1

### INTRODUCTION

There is a wide range of motors and motor characteristics in existence, because of the numerous duties for which they are used, and all of them need protection. Fortunately, the more fundamental problems affecting the choice of protection are independent of the type of motor and the type of load to which it is connected.

Motor characteristics must be carefully considered when applying protection; while this may be regarded as stating the obvious, it is emphasized because it applies more to motors than to other items of power system plant. For example, the starting and stalling currents and times must of necessity be known when applying overload protection, and furthermore the thermal withstand of the machine under balanced and unbalanced loading must be clearly defined.

The conditions for which motor protection is required can be divided into two broad categories: imposed external conditions and internal faults. The former category includes unbalanced supply voltages, undervoltage, single-phasing and reverse phase sequence starting, and, in the case of synchronous machines only, loss of synchronism. The latter category includes bearing failures, internal shunt faults, which are most commonly earth faults, and overloads.

The protection applied to a particular machine depends on its size and the nature of the load to which it is connected. However, all motors should be provided with overload and unbalanced voltage protection, and this can very often be provided in a single relay.

## 20.2

### BEARING FAILURES

There are two types of bearings to be considered: the anti-friction bearing (ball or roller), used mainly on small motors (up to 500 h.p.), and the sleeve bearing, used mainly on large motors.

The failure of ball or roller bearing usually occurs very quickly, causing the motor to come to a standstill as pieces of the damaged roller get entangled with the others. There is therefore very little chance that any relay operating from the input current can detect bearing failures of this type before the bearing is completely destroyed. Even so, it is essential for the relay to disconnect the motor as quickly as possible to avoid damage to the motor windings.

The fact that a sleeve bearing is about to fail can be detected by means of a temperature device embedded in the bearing, as the bearing temperature will increase if the lubrication system fails. It is generally accepted that, on the loss of bearing oil, the bearing will tend to seize in one or two minutes, causing the white metal to flow away; the increase in motor current before this would only be of the order of 10–20%. So if the normal thermal overload relays are to match the motor thermal characteristics adequately, they cannot give protection to the bearing itself, but will operate fast enough to protect the motor from excessive damage.

### 20.3

#### FAILURE OF MOTORS BY WINDING INSULATION

The majority of winding failures are either indirectly or directly caused by overloading (either prolonged or cyclic), operation on unbalanced supply voltages, or single-phasing, which all lead to the deterioration of the insulation until an electrical fault occurs in the winding.

### 20.4

#### PROTECTION OF MOTORS BY OVERLOAD RELAYS

The wide diversity of motor duties and motor designs makes it well-nigh impossible to cover all types and ratings of motors with a given characteristic curve. Two typical examples of motor duties for which differing degrees of protection are preferred are given below:

a. Motors used on fluctuating loads where the loss of the motor would shut down the whole process. In this case it might be advisable to leave the motor running as long as possible, usually achieved in practice by giving the relay a higher current setting.

b. Motors connected to a steady load. These can be tripped off more quickly, as any overload will probably be due to a mechanical fault which cannot be rectified in time.

In general, not all the information required to set overload relays accurately will be available for each individual machine; it is therefore only feasible to design protection that matches as closely as possible the heating characteristics of the majority of motors. Care must be taken to ensure that the operating time of the relay will allow the motor to start, taking into account the over-run time of the relay.

### 20.5

#### RELATIONSHIP BETWEEN MOTOR STARTING AND STALLING CURRENTS

As the magnitude and duration of motor starting currents and the magnitude and permissible duration of motor stalling currents are major factors to be considered in the application of overload protection, these will be discussed in some detail. It is commonly assumed that for machines started direct on line the magnitude of the starting current decreases linearly as the speed of the machine builds up during starting. This does not in fact apply to any machine; for normal designs the starting current remains approximately constant at the initial standstill value for 80–90% of the total starting time.

The rotor current  $I_r$  of an induction motor corresponding to any value of slip  $S$  can be shown to be given by:

$$I_r = \frac{KE}{\left(\frac{R^2}{S^2} + X^2\right)^{1/2}} \quad \dots \text{Equation 20.1}$$

From Equation 20.1, and assuming that the machine reactance is equal to ten times the machine resistance, the starting curve of the machine can be derived as shown in Figure 20.1.

Equation 20.1 indicates that, for motors with low rotor resistance ( $R/S$ )<sup>2</sup> only becomes large compared with  $X^2$

as the value of slip becomes small. Thus, as shown in Figure 20.1, the starting current remains substantially equal to the current at standstill until the motor is almost up to its normal running speed.

When determining the current and time settings of the overload protection it is normally assumed that the motor starting current remains constant and equal to the standstill current for the whole of the starting period.

### 20.6

#### STALLING OF MOTORS

Should a motor stall when running or be unable to start because of excessive load, it will draw a current from the supply equivalent to the locked rotor current. It is obviously desirable to avoid damage by disconnecting the machine as quickly as possible if this condition arises.

It is not possible to distinguish this condition from a healthy starting condition purely on a current magnitude basis; the only way to overcome the problem is to arrange that the protective device disconnects the motor if the current continues for longer than the normal starting time.

The majority of loads are such that the starting time of normal induction motors is under 10 seconds, while the allowable stall time to avoid excessive deterioration of the motor insulation is in excess of 20 seconds. It is therefore relatively easy to discriminate between the two conditions on a time basis.

In the case of motors used for special applications, for example motors driving high inertia loads, the starting time may be prolonged, becoming nearly equal to the safe stall time and making the problem of discrimination between the two conditions much more difficult. In these cases, depending on the type of relay used for overload protection, it may be necessary to use a relay initiated from the starting device especially to protect against a stalling condition.

Whether or not additional stalling protection will be needed in any application depends mainly on the ratio of the normal starting time to the allowable stall time and the closeness with which the overload relay can be set to match the stalling time/current curve without the possibility of maloperation on a healthy start. This is indicated in Figure 20.2(a), which shows that if the operating time of the overload relay is substantially above the starting time but below the allowable stall time, protection is given; but if, as shown in Figure 20.2(b), the overload relay time is

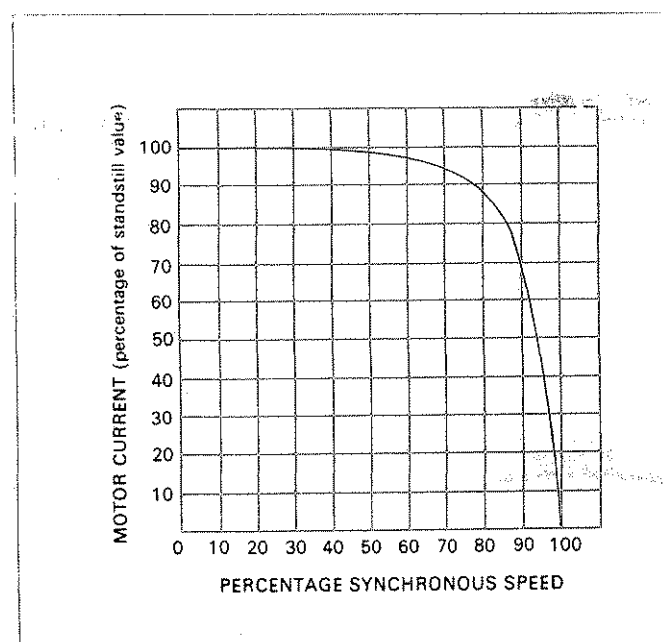


Figure 20.1 Typical motor starting current/speed curve

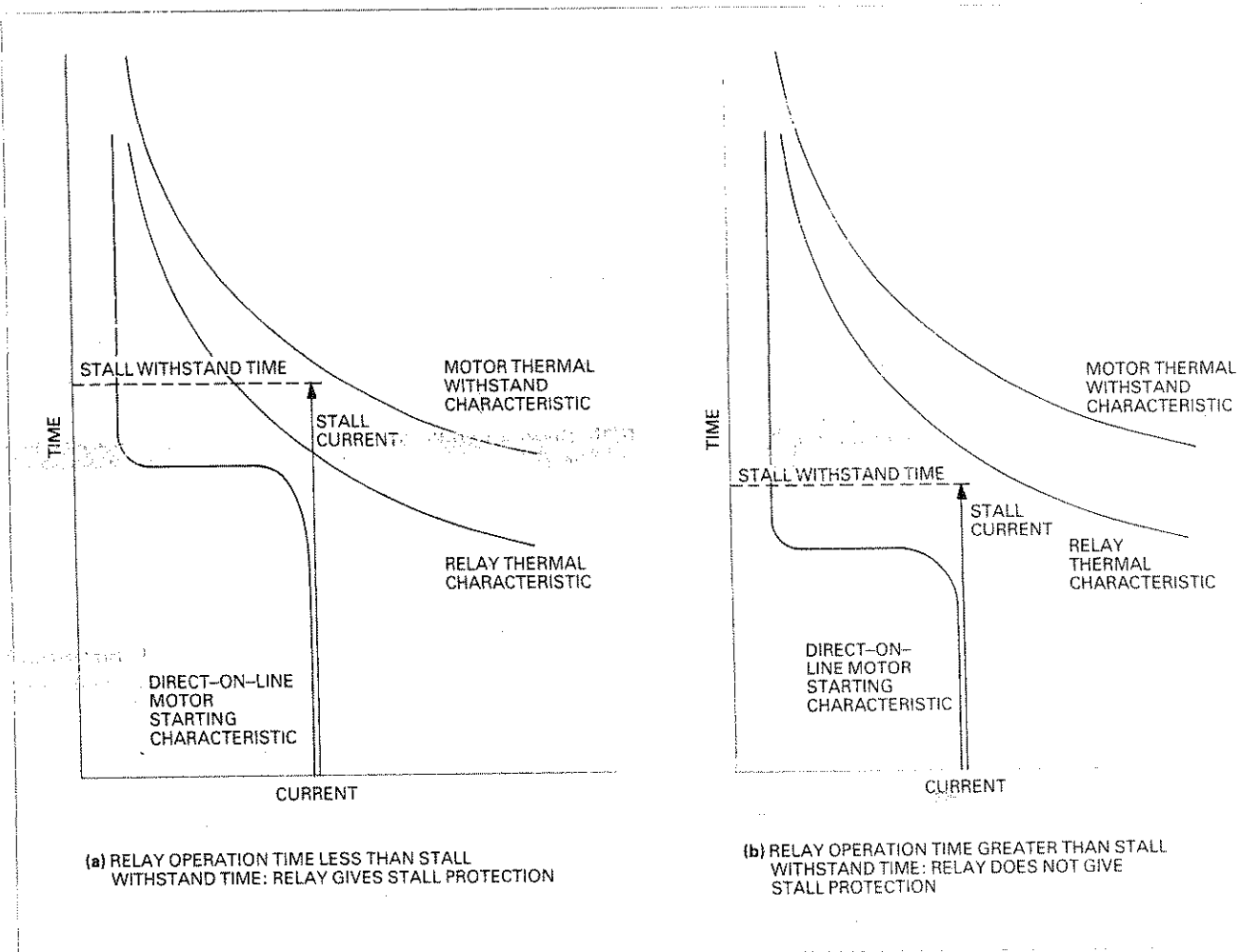


Figure 20.2 Stall protection principle. Direct-on-line start current = stall current.

longer than the allowable stall time, then a separate definite time relay is required. A further difficulty is sometimes encountered when the stall withstand time of the motor is less than the starting time. If stall protection is required during starting as well as running in this situation a separate stalling relay is used in conjunction with a shaft speed monitor (tacho-switch).

Many types of motor overload protection relays are in use ranging from simple dashpot and thermal devices to versatile static protection relays.

The thermal overload relay, in which a bimetal spiral in proximity to a heater acts as the contact actuating device, has a fairly high percentage overrun of the order of 45% at six times rated current. If a relay of this type has say, an operating time of 20 s at six times rated current, then the maximum starting time of any motor at six times rated current should be limited to 11 s, so as to ensure that the overrun does not exceed the 20 s relay operation time and thereby cause any unnecessary tripping of the motor.

Because of the large percentage overrun with this relay type, an additional relay is often required to provide adequate protection against stalling conditions.

When using a static relay however, the percentage overrun is small, so the relay is usually able to give both overload and stalling protection. In motor applications where a separate stalling relay is required, stalling relays type CTS are available in several configurations, shown in Figure 20.3, as follows:

Type CTS 11 (Figure 20.3(a)): This is a simple overcurrent time relay for use, as mentioned previously, where the stall withstand time exceeds the starting time.

Type CTS 12 (Figure 20.3(b)): Where the safe stall time is less than the starting time, an additional time delay is used

to inhibit operation over the starting period. Accordingly, stall protection is given for the running condition only.

Type CTS 13 (Figure 20.3(c)): This relay configuration can be used where the safe stall time is less than the starting time and stall protection is required for both the starting and the running conditions. A signal from a shaft mounted tacho-switch is used to initiate a time delay via an interlock contact on the motor starting device. The time delay is set at less than the motor safe stall time. The tacho-switch is set to open at 10% rated speed and during a satisfactory start will operate well within the timing period. Should the motor stall when running, actuation of the tacho-switch will initiate the time delay and cause tripping.

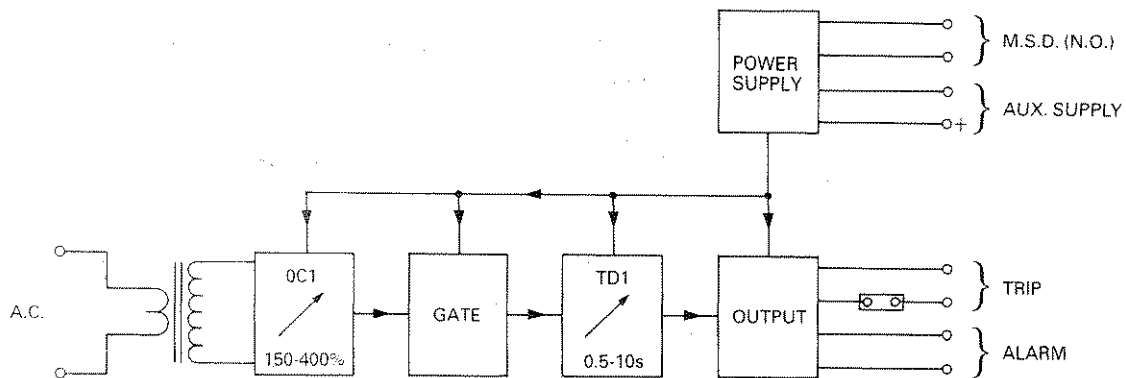
Type CTS 14 (Figure 20.3(d)): This is similar in operation to the CTS 13, the interlock contact on the motor starting device being replaced with an independent time overcurrent unit.

Type CTS 15 (Figure 20.3(e)): This relay is intended for use where the safe stall time is less than the starting time, and stall protection is required on starting and also on running, even though shaft speed does not fall low enough to operate the tacho-switch.

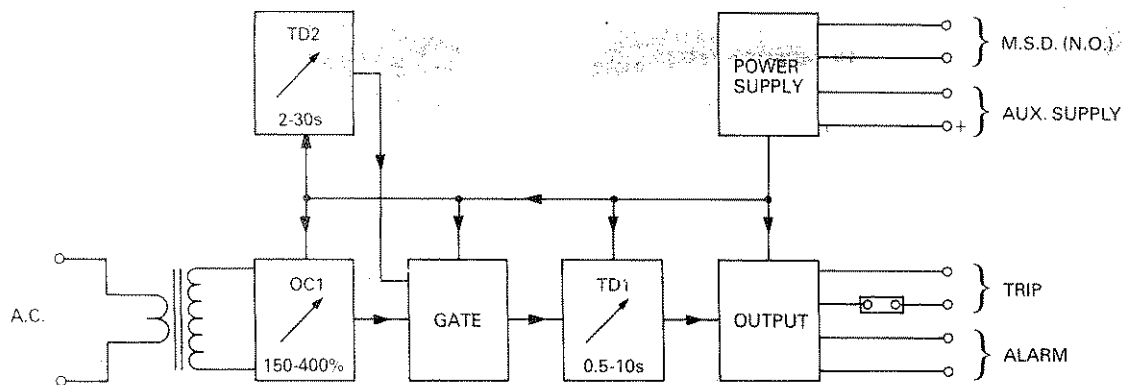
The relay is initiated by a contact on the motor starting device. The time delay element TD2 is operated either from the tacho-switch or from an overcurrent unit. The overcurrent unit is set above full load and the accelerating current but less than locked rotor current, and on starting is inhibited by TD1, stall protection being given by the tacho-switch and TD2. When running, stall protection is given by the overcurrent unit or the tacho-switch operating TD2.

All of the foregoing comments regarding stalling assume that the motor remains connected to a three-phase

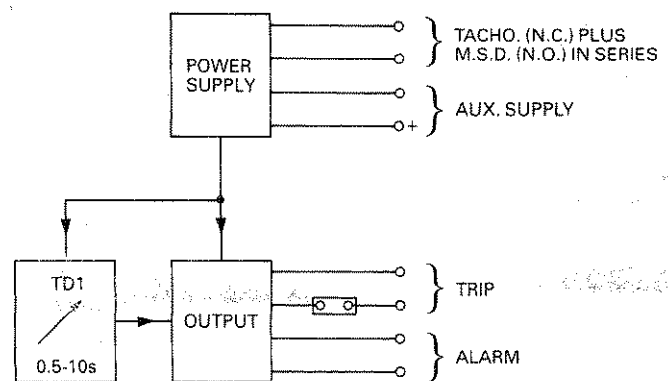




(a) CTS 11: INDEPENDENT TIME OVERCURRENT.



(b) CTS 12: INDEPENDENT TIME OVERCURRENT PLUS STARTING TIME DELAY



(c) CTS 13: TIMER PLUS TACHOSWITCH INTERLOCK

(M.S.D. = Motor Starting Device)

Figure 20.3 Type CTS stalling relays.

balanced supply, but the most likely cause of stalling in induction motors is the loss of one phase of the supply, caused perhaps by the blowing of a back-up fuse by the inrush current when the motor is first energized.

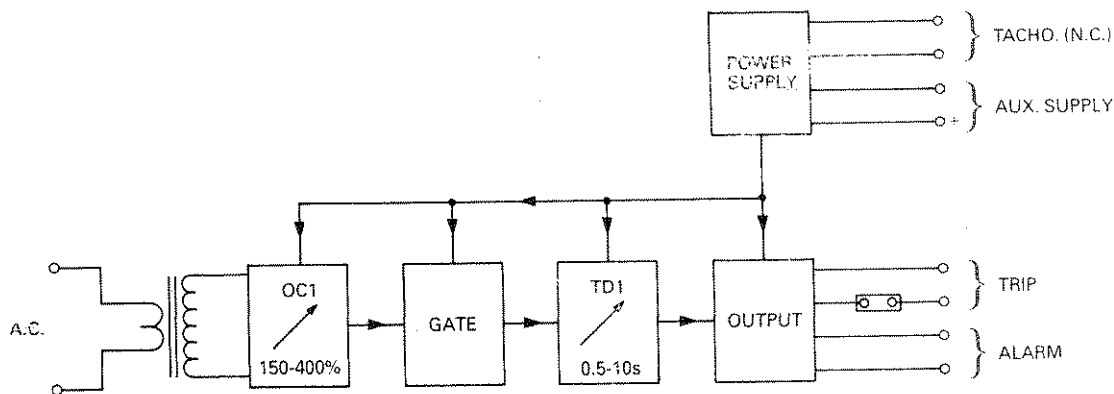
Under this condition the motor will fail to start and will remain stationary with a single phase supply applied to the stator terminals. Also, the motor may stall if one phase is open circuited while the motor is running, depending on the load on the machine at the time of the open circuit. The actual value of the current drawn by the machine will be less than the three phase stalling current, being equal to 0.866 of this value; however, excessive overheating of parts of the rotor winding is likely to ensue.

With a balanced three-phase supply applied to the

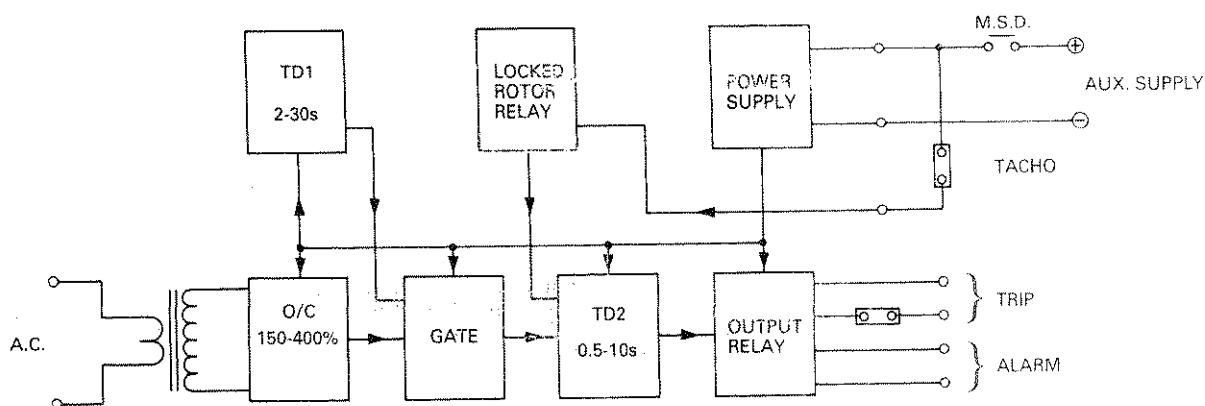
machine a rotating flux is induced in the rotor, causing symmetrical heating of the rotor winding.

With unbalanced supply voltages, as in the case of the loss of one phase, there is a pulsating flux induced in the rotor which is the sum of the fluxes due to the positive and negative phase sequence currents. This causes unequal heating of the rotor winding depending on the position of the rotor bars.

There have been cases where the rotor bars of an induction motor have been severely damaged because a single phase supply has been applied while the motor was stationary. For this reason it is essential that for this condition the motor is disconnected from the supply as quickly as possible.



(d) CTS 14: INDEPENDENT TIME OVERCURRENT PLUS TACHOSWITCH INTERLOCK



(e) CTS15: OVERCURRENT WITH STARTING TIME DELAY AND TACHO SWITCH INTERLOCK (M.S.D. = Motor Starting Device)

Figure 20.3 Type CTS stalling relays (continued).

## 20.7

When a three-phase induction motor is supplied from a three-phase supply, the voltage supplied to the motor can be unbalanced for a variety of reasons: single-phase loads, imperfect transposition of feeders or blown fuses in power factor correction plant. In addition, the accidental opening of one phase lead in the supply to the motor can, depending on the load, leave the motor still running, supplied by two phases only.

At first sight it might appear that the degree of voltage unbalance met with in a normal installation (except when one line is open-circuited) would not affect the motor to any great extent, but it should be remembered that it is not the unbalanced voltage which is of importance but the relatively much larger negative sequence component of the unbalanced current in the machine windings that results from the unbalanced voltage.

The condition of an open circuit in one line of the supply to a three-phase induction motor is often regarded as the worst possible case of unbalance likely to cause overheating of the machine windings.

For most practical values of voltage unbalance this is probably true, but it need not necessarily be so. The equivalent circuit of an induction motor with one phase open-circuited is as shown in Figure 20.4, from which it can be

seen that the positive and negative sequence impedance networks are connected in series. For this particular condition, therefore, the positive and negative sequence currents must be equal in magnitude.

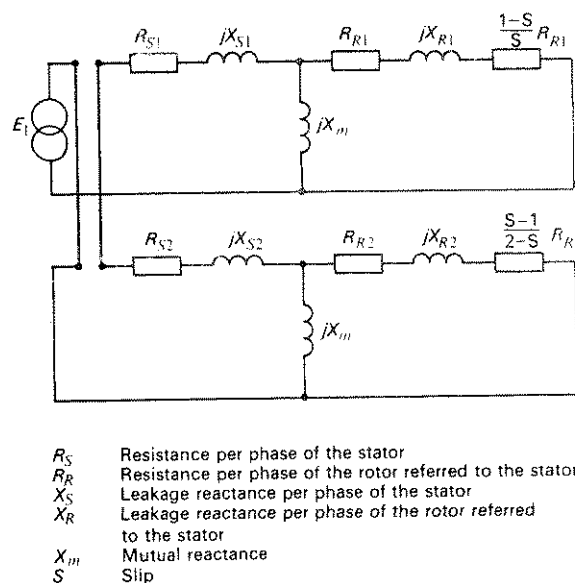


Figure 20.4 Equivalent circuit of induction motor with one phase open-circuited.

In the general case of unbalance of the three phase voltages there is no fixed relationship between the positive and negative sequence currents; the actual value of the negative sequence current depends on the degree of unbalance in the supply voltage, and also on the ratio of the negative to the positive sequence impedance of the machine.

This ratio can be determined from the general equivalent circuit of the induction motor shown in Figure 20.5, in which the magnetizing impedance of the motor has not been included.

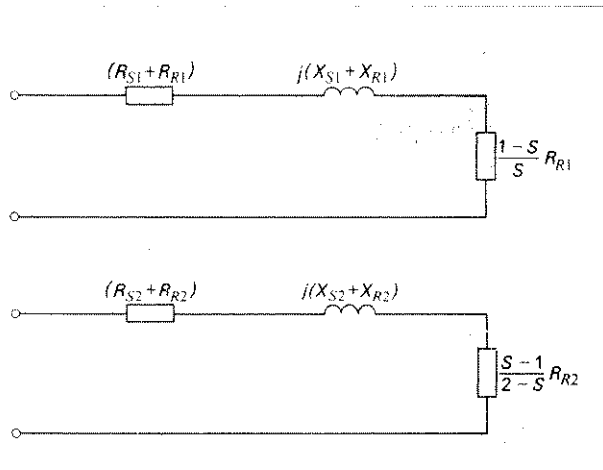


Figure 20.5 General equivalent circuits of induction motor.

The positive sequence impedance of the machine at any value of slip is equal to:

$$\left[ \left( R_{S1} + \frac{R_{R1}}{S} \right)^2 + (X_{S1} + X_{R1})^2 \right]^{1/2}$$

At standstill, when  $S = 1$ , this is equal to:

$$[(R_{S1} + R_{R1})^2 + (X_{S1} + X_{R1})^2]^{1/2}$$

The negative sequence impedance of the machine at any value of slip is equal to:

$$\left[ \left( R_{S2} + \frac{R_{R2}}{2-S} \right)^2 + (X_{S2} + X_{R2})^2 \right]^{1/2}$$

At normal running speed, when  $S$  is small, this is equal to:

$$\left[ \left( R_{S2} + \frac{R_{R2}}{2} \right)^2 + (X_{S2} + X_{R2})^2 \right]^{1/2}$$

Since in an induction motor the value of the resistance is normally small compared with the reactance, the negative sequence impedance at normal running speeds can be approximated to the positive sequence impedance at standstill. The ratio of the positive sequence impedance to the negative sequence impedance at normal running speeds can thus be approximated to the ratio of the starting current to the normal full load running current, and the negative sequence current will therefore be approximately equal to the product of the negative sequence voltage and the ratio of the starting current to the full load running current.

For instance, in a motor which has a starting current equal to six times rated current, a 5% negative sequence component in the supply voltage would result in approximately a 30% negative sequence component of current. If in the above example the negative sequence component in the unbalanced voltage exceeded 17% of the positive

sequence component, the negative sequence current would be greater than the positive sequence current.

Even if one phase is open-circuited, it is still possible for the negative sequence component to exceed the positive sequence component; this depends on the position of the open circuit in the supply network. If the motor is supplied from the same busbars as a static load and an open circuit occurs in one of the supply lines to the combined load as shown in Figure 20.6(a), it is possible that the negative sequence current will exceed the positive sequence current in the motor circuit. This can be seen from an examination of the sequence impedance diagram shown in Figure 20.6(b).

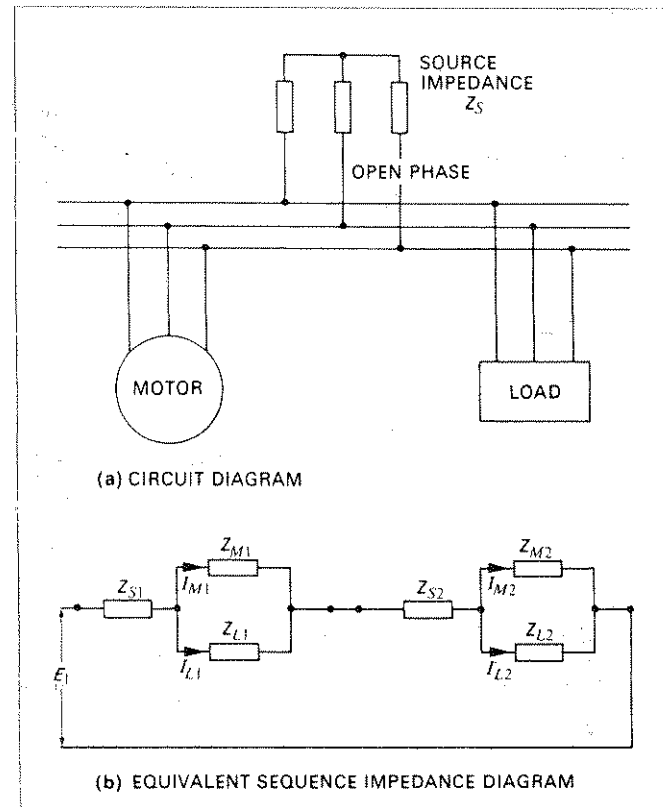


Figure 20.6 Conditions for negative sequence current to exceed positive sequence current.

The total sequence currents, that is,  $(I_{M1} + I_{L1})$  and  $(I_{M2} + I_{L2})$ , are equal, but, as shown above,  $Z_{M2} < Z_{M1}$ , so the distribution of the two sequence currents through the motor and load circuit is different, resulting in a larger proportion of the total negative sequence current flowing in the motor.

## 20.9

### DE-RATING OF MACHINE DUE TO UNBALANCED CURRENTS

The negative sequence component of the current does not contribute to providing the driving torque of the motor; in fact, it produces a small negative torque. The magnitude of the torque due to the negative sequence current is, however, usually less than 0.5% of the full load rated torque for a voltage unbalance of the order of 10% and can therefore be neglected.

The main effect of the negative sequence current is to increase the motor losses, mainly copper loss, thus reducing the available output of the machine if overheating of the machine windings is to be avoided. The reduction in output for machines having ratios of starting to running current of 4, 6 and 8 respectively is shown in Figure 20.7 for various ratios of negative to positive sequence voltage.

In calculating these figures it has been assumed that:

i. The positive sequence current under unbalanced conditions is the same as the current under balanced conditions, that is, the machine maintains the same output, an assumption which is valid for small values of negative sequence applied voltage.

ii. Perfect heat conductivity between the individual phase windings in the stator exists, that is, the temperature rise in each phase winding has been related to the average phase current.

Unbalanced phase currents flowing in the stator of a machine tend to cause the phase or phases carrying the highest value of current to reach a higher temperature than the other phase windings. Some of the additional heat generated in these windings will be dissipated through the stator iron with the result that all the phase windings will come nearer to reaching an equal temperature. The steady state temperature of the phase carrying the highest current will be proportional to the square of the winding current for a machine with very poor thermal conductivity, and proportional to  $(I_A^2 + I_B^2 + I_C^2)/3$ , that is, the average motor heating, for a machine with perfect thermal conductivity between phases. For small values of unbalance current it is reasonable to assume that there will be sufficient time for all the phase windings to reach an equal temperature by the conduction of heat through the stator iron before excessive overheating takes place in the windings of the most heavily loaded phase. The time taken for the end windings of the machine, which are not in contact with the iron, to approach the average temperature would be longer, but as the maximum temperature of the end windings is less than that of the embedded portion this will tend to be self-compensating.

The actual distribution of heating throughout the stator winding will depend to a great extent on the phase relationship between the positive and negative sequence components of the unbalanced line currents.

In Figure 20.8 the positive and negative sequence currents of phase A are assumed to be in phase. If the negative sequence component of the supply voltage is 5%, the negative sequence current will be 30% for a motor with a  $Z_1/Z_2$  ratio of 6. The values of the phase currents on a per unit basis are, for  $I_A$ , 1.3, and for  $I_B$  and  $I_C$ , 0.89, giving a

corresponding copper loss in phase A of 1.69 and in phases B and C of 0.79. In this case, only one phase has a copper loss above normal and the other two much cooler phases will provide a good heat sink, thus tending to even out the temperature of all three phases.

In Figure 20.9 the positive and negative sequence components of phase A are assumed to be  $180^\circ$  out of phase and the copper losses in the three phases corresponding to a 5% negative sequence voltage are, for  $I_A$ , 0.49, and for  $I_B$  and  $I_C$ , 1.37.

In this case two phases have a copper loss above normal and there is only a third of the stator to act as a heat sink. Because of this and because the copper loss in the two phases is in any case near the average loss, it is more likely that little heat will be transferred from these two phases. In general, only when excessive unbalance occurs on the higher voltage machines, where conductor insulation is necessarily increased, does the temperature of the most heavily loaded phase appreciably exceed the average stator temperature.

## 20.10

Any relay used to protect the machine stator windings against unbalanced currents should ideally have an operating characteristic which lies slightly above the average copper loss curve for small degrees of unbalance; see Figure 20.8 for the phase A and the average stator copper

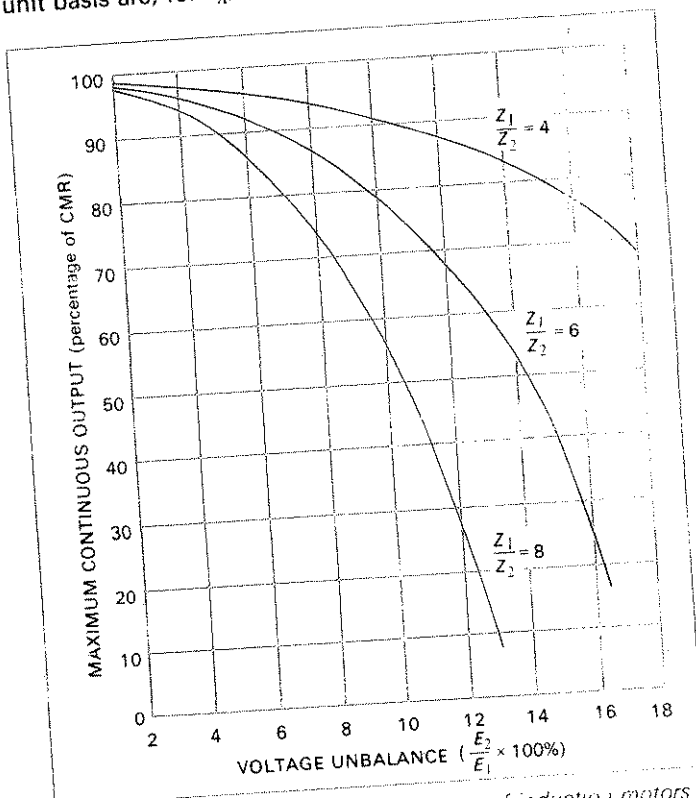


Figure 20.7 Reduction in available output of induction motors with unbalanced supply voltages.

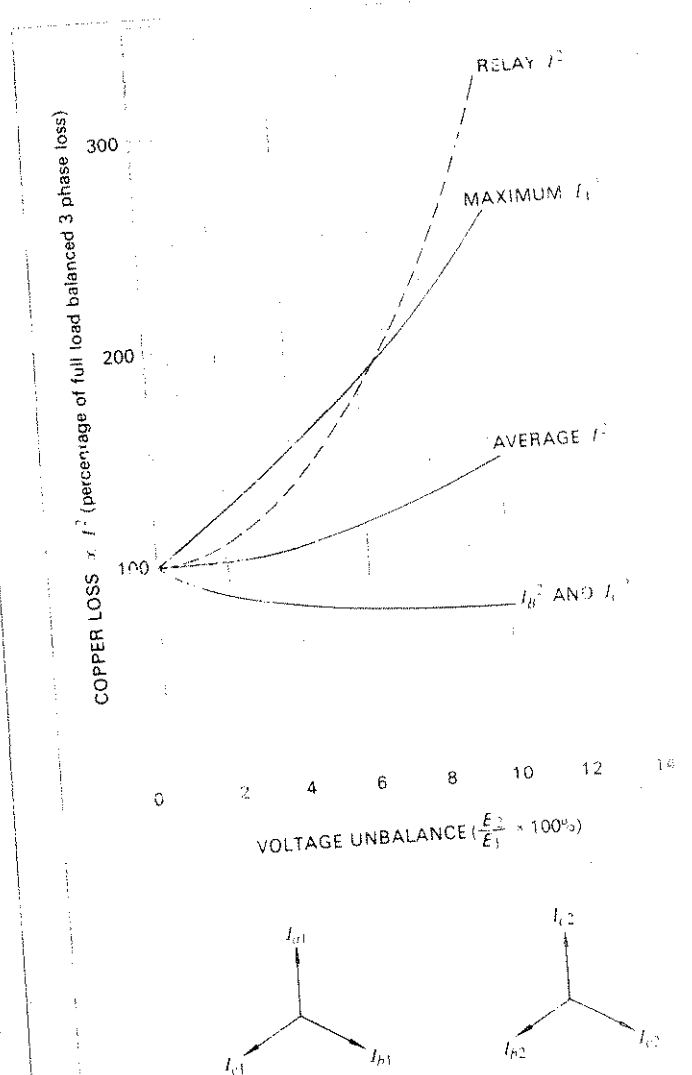


Figure 20.8 Characteristics of motor with  $Z_1/Z_2$  ratio equal to 6 ( $I_{a1}$  in phase with  $I_{a2}$ ).

loss curves. In this situation there is sufficient time for the machine windings to reach an even temperature before excessive overheating occurs in one phase.

For higher values of unbalance the operating characteristic should lie above the maximum copper loss curve for phase A.

## 20.11

The variations of rotor resistance with frequency have been neglected in arriving at the curves shown in Figure 20.7. This is not generally a valid assumption, because of the effect of the high frequency currents induced in the rotor by the negative sequence component of the stator currents.

The frequency of these currents is equal to  $(2-S)$  times the nominal frequency of the supply. The resistance of the motor windings is increased by the skin effect, the actual value depending mainly on the depth of the winding in the rotor slots. In squirrel-cage machines the ratio of the 100 Hz a.c. resistance to the d.c. resistance varies from 1.25 to 6. The rotor heating due to the positive sequence component of the stator current is proportional to the d.c. resistance value, while the heating effect on the rotor windings of the negative sequence component is proportional to the 100 Hz a.c. resistance value.

It is clear, therefore, that the heating effect of one unit of negative sequence current is greater than the heating effect of one unit of positive sequence current. Any overload device used to protect the motor must take this into account if it is to decide correctly what load the motor can

stand for a given degree of voltage unbalance without overheating.

The criterion for the design of a relay used to protect a motor under unbalanced voltage conditions is that, while it should prevent prolonged overloads on the motor from causing excessive heating in either the machine stator or rotor, it should not disconnect the motor unnecessarily, and so cause loss of output. The degree to which this objective is achieved by various types of relay will now be considered.

## 20.12

### SINGLE-PHASE OVERCURRENT RELAYS

By examining the unbalance condition depicted in Figure 20.8, it can be seen that in order to ensure that the maximum phase current is detected, three single-phase overcurrent relays must be used. As explained previously, an overcurrent relay connected to measure phase A current would disconnect the machine unnecessarily for small values of unbalance, while relays connected in phases B and C could not protect the machine adequately throughout the whole range of unbalance currents.

In addition, if a phase is open-circuited in one of the supply leads to a delta-connected motor (a severe case of unbalance), the percentage increase in current in the one winding connected across the two healthy phases is greater than the increase in the line currents, and as a result, in this situation single-phase overcurrent relays may not fully protect the machine stator windings. Figure 20.10 shows the results of tests carried out on a 12.5 h.p. squirrel-cage induction motor with an open circuit in line C. The

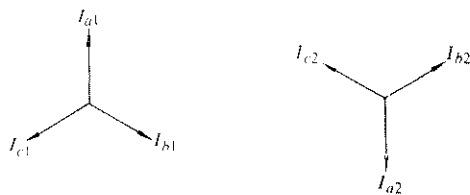
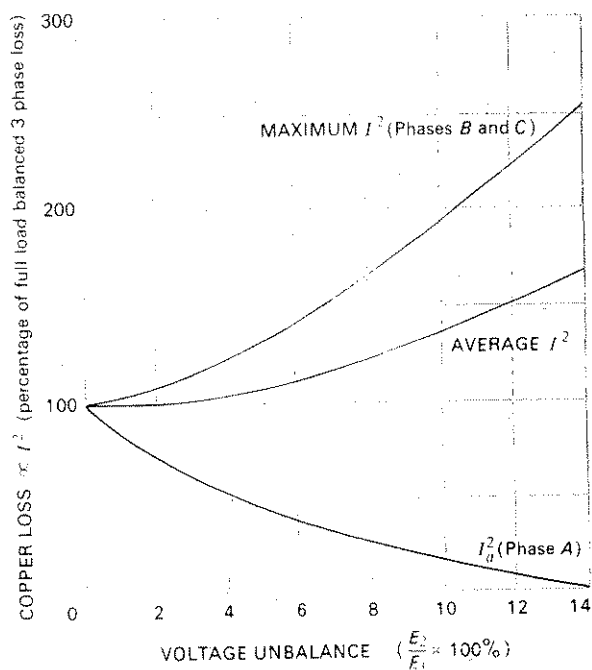


Figure 20.9 Characteristics of motor with  $Z_1/Z_2$  ratio equal to 6 ( $I_{a1}$  in anti-phase to  $I_{a2}$ ).

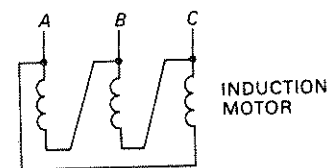
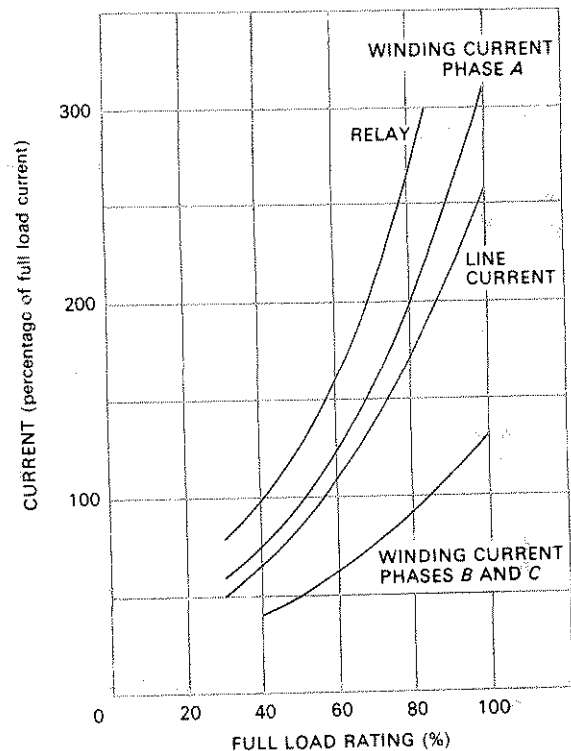


Figure 20.10 Motor line and winding currents with one supply line open-circuited (phase C).

values of the healthy line currents and the maximum (phase A) winding current are expressed as percentages of the full load current under three-phase balanced conditions and plotted for different motor loadings. It will be seen that the maximum winding current is relatively greater than the line currents; in this situation, therefore, over-current relays in the lines cannot adequately protect the machine windings, nor can this type of relay allow for the additional heating effect in the rotor circuit caused by the negative sequence current.

## 20.13

### PHASE UNBALANCE RELAYS

Relays that operate when the unbalance in the line currents exceeds a given value are often used to protect motors when running with unbalanced supply voltages.

These relays suffer from the following disadvantages:

a. They operate only on the difference in magnitude of the line currents, not on the phase and magnitude difference. They cannot therefore measure accurately the value of the negative sequence current which is the main cause of the additional heating in the rotor windings due to unbalance.

b. They tend to be too sensitive both under single-phasing conditions and at small values of unbalance, thus disconnecting the motor unnecessarily.

Under single-phasing conditions excessive heating can occur in the stator windings only if the current in one or more phases exceeds the normal full load value. The unbalance feature of this type of relay operates with 40% of full load current flowing in two phases only and will therefore trip the machine unnecessarily as far as stator heating is concerned. Additional heating will take place in the rotor circuit because of the presence of the negative sequence component, but the actual value of this that will operate the relay with the above setting is  $40/1.732\%$ , that is,  $23\%$ ; in other words, the heating will be proportional to  $(0.23)^2$  or  $5.4\%$  of normal, and the total heating, assuming no increase in rotor resistance, will be proportional to  $(I_1^2 + I_2^2)$ , or  $10.8\%$  of normal full load.

If the motor is running on full load and the three phase voltages become unbalanced so that there is  $12\%$  unbalance in the line currents, relays of this type will operate after about 15 minutes because of the unbalanced currents.

If the motor is to continue to deliver full load torque, the positive sequence current will remain substantially constant at the  $100\%$  value and the heating in the motor stator windings will be as shown in Figures 20.8 and 20.9.

The negative sequence current corresponding to  $12\%$  unbalance in the line currents can be shown to be  $8\%$ , which corresponds to a negative sequence voltage of  $1.3\%$  for a motor with a  $Z_1/Z_2$  ratio of 6.

As stated previously, there is ample time with small values of unbalance for the heat generated in the phase winding carrying the largest current to be dissipated through the stator iron to the other phases, resulting in all the phases reaching approximately the same temperature. It will be seen from Figure 20.8 that the increase in the average copper loss corresponding to  $1.3\%$  negative sequence voltage is less than  $1\%$ , so the average winding temperature will be substantially equal to the normal full load value.

The heating due to the negative sequence current will be proportional to  $(0.08)^2$ , that is, only  $0.64\%$  of normal. Even allowing for the greater relative heating caused by the negative sequence current in the machine rotor windings, a relay with this setting will disconnect a machine with unbalanced supply voltages long before it need be shut down to avoid overheating in either the stator or rotor windings.

If a relay is to protect motors running with unbalanced

supply voltages and is to follow closely the heating of the motor windings, it must be able to determine accurately the magnitude of the negative sequence component of the unbalanced line currents. If the machine maintains the same output and continues to run at the same speed under unbalanced voltage conditions as under balanced conditions, the positive sequence component of the line currents will be substantially the same as the balanced three-phase currents. The heating due to the positive sequence component will therefore be identical to that under balanced voltage conditions, any additional heating being caused by the presence of the negative sequence component. It has been shown previously that the heating effect of one unit of negative sequence current is greater than that of one unit of positive sequence current, and for the relay to protect the machine adequately this must be allowed for in the design of the relay.

In general, the larger the motor the more prone it is to damage under unbalance conditions, mainly because of the relatively high rotor resistance to the  $100\text{ Hz}$  negative sequence current. In addition, at the higher values of unbalance the losses in the stator phases carrying the higher currents are not so evenly distributed, because the distances between phases is too great for the individual phase temperatures to equalize.

Test figures available on the temperature rise in the rotors of squirrel-cage induction motors indicate that, on the larger machines of approximately  $1000\text{ h.p.}$  and above, excessive overheating due to operation on unbalance voltages can be avoided if the rating of motors having a starting current of six times rated current is reduced by about  $20\%$  for a negative sequence voltage of  $5\%$ , and by about  $60\%$  for a negative sequence voltage of  $7\%$ . The ratings of motors having higher starting currents should be further reduced and the ratings of those with lower starting currents can be correspondingly increased.

The above test figures show that the actual de-rating factors to be applied are, as expected, somewhat greater than those obtained from Figure 20.7.

## 20.14

### FAULTS IN THE MOTOR WINDINGS

#### 20.14.1

##### Earth faults

Faults which occur within the motor windings are mainly earth faults caused by a breakdown in the winding insulation. This type of fault can be very easily detected by means of a simple instantaneous overcurrent relay, usually with a setting of approximately  $20\%$  of the motor full load current, connected in the residual circuit of three current transformers.

Care must be taken to ensure that the relay does not operate from spill current due to the saturation of one or more current transformers during the initial peak of the starting current; this can be as high as  $2.5$  times the steady state r.m.s. value, and may cause operation, given the fast operating speed of the normal relay. To achieve stability under these conditions, it is usual to increase the minimum operating voltage of the relay by inserting a stabilizing resistor in series with it.

#### 20.14.2

##### Phase-phase faults

Because of the relatively greater amount of insulation between phase windings, faults between phases seldom occur. As the stator windings are completely enclosed in grounded metal the fault would very quickly involve earth, which would then operate the instantaneous earth fault protection described above.

Differential protection is sometimes provided on large and

important motors to protect against phase-phase faults, but if the motor is connected to an earthed system there does not seem to be any great benefit to be gained if a fast-operating and sensitive earth fault protection is already provided.

### 20.14.3 Interturn faults

Unless each phase winding of the stator is divided into two or more circuits, the protection available to detect this condition is rather complex and for this reason is not normally applied.

### 20.14.4 Terminal faults

High set instantaneous overcurrent relays are often provided to protect against phase faults occurring at the motor terminals, such as terminal flashovers. Care must be taken when setting these units to ensure that they do not operate on the initial peak of the motor starting current, which can be 2.5 times the steady state r.m.s. value. The asymmetry in the starting current rapidly decreases, and has generally fallen to its steady state value after one cycle. A typical oscillogram of motor starting current is shown in Figure 20.11.

### 20.15 FAULTS IN ROTOR WINDINGS

On wound rotor machines some degree of protection against faults in the rotor winding can be given by an instantaneous overcurrent relay that measures the stator current. As the starting current is normally limited by resistance to a maximum of twice full load, the instantaneous unit can safely be set to about three times full load if a slight time delay of approximately 30 milliseconds is incorporated. It should be noted that faults occurring in the rotor winding will not be detected by any differential protection applied to the stator.

### 20.16 MODERN RELAY DESIGN

The design of a modern motor protection relay must be adequate to cater for the protection needs of any one of the vast range of motor designs in service, many of the designs having no permissible allowance for overloads.

Since the relay should ideally be matched to the protected motor and be capable of close sustained overload protection, a wide range of relay adjustment is desirable together with good accuracy and low thermal overshoot. Furthermore, since the thermal withstand capability of the motor is affected by heating in the winding prior to a fault, it is important that the relay characteristic takes account of the extremes of zero pre-fault current known as the 'Cold' condition and full rated current pre-fault, known as the 'Hot' condition.

The 'Cold' and 'Hot' relay characteristics relating to the above conditions are defined in the International Electrotechnical Commission (IEC) Standard 255-8 for Thermal Electrical Relays. This defines the 'Cold' thermal withstand characteristic as follows:

$$t_c = \tau \cdot \log_e \frac{I^2}{I^2 - (K I_B)^2}$$

where  $t_c$  = Operating time (cold) (s)

$\tau$  = Heating time constant (s)

$I_B$  = Basic current of relay. (Thermal relay settings are made in terms of this current). (A)

$I$  = Current in relay. (A)

$K$  = Constant by which  $I_B$  is multiplied to obtain the accuracy reference current value.

When a motor is, or has been, running prior to a fault, the windings will already be dissipating heat and the 'Hot' characteristic is applicable; this is defined in IEC255-8 as:

$$t_h = \tau \cdot \log_e \frac{I^2 - I_p^2}{I^2 - (K I_B)^2}$$

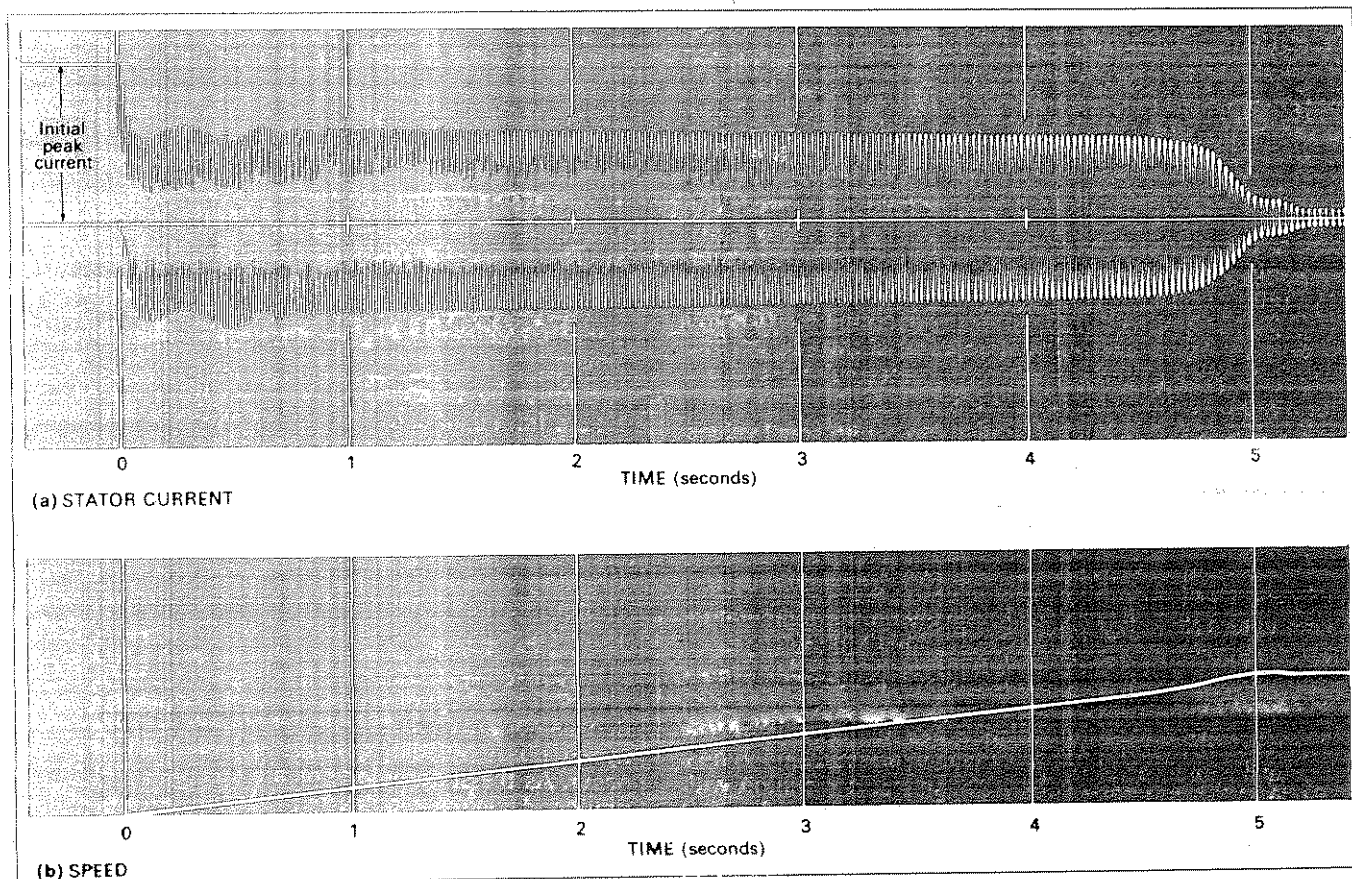


Figure 20.11 Direct-on-line starting characteristics for a typical induction motor, showing starting current and run-up speed.



where  $t_h$  = Operating time (hot)(s)  
 $I_p$  = Specified load current before the overload occurs. (A)

The majority of modern motor protection relays are of the thermal replica type with characteristics conforming to the above and adjustable over a wide range. It is also desirable to include in the relay protection for unbalance/single phasing conditions and also earth faults.

GEC ALSTHOM Measurements have two thermal replica modular motor protection relays in the MIDOS range, designated type MCHN and type MCHG.

### 20.16.1 Modular relay type MCHN

The relay type MCHN, shown in Figure 20.12, is a comprehensive motor protection relay with flexible adjustment designed to give a high level of motor protection.

The facilities offered by the relay are:

- Thermal replica protection trip.
- Pre-trip alarm.
- Short circuit protection.
- Negative sequence current detection.
- Earth fault protection.
- Extended start protection.
- Stalling protection.
- Auxiliary supply supervision.

The relay thermal replica characteristic is as defined by IEC 255-8 and is set by the heating time constant control  $\tau_1$  which is adjustable from 0 to 37.5 minutes, as shown in Figure 20.13. Adjustment of the cooling time constant  $\tau_2$  over a range of 1 to  $4.5\tau_1$  is also possible, and in addition the ratio of cold/hot characteristics can be set by internal links, the available ratios being 1.5/1, 2/1, 2.5/1, 3/1 and 10/1, so enabling the relay to be matched to a wide range of motor designs.

A pre-trip alarm, adjustable from 70% to 100% of the tripping value, is included together with an instrument to indicate the level of heat equivalent in the thermal replica.

The relay characteristic is produced by separating the positive and negative sequence components of the line currents by means of a sequence filter, so giving a high level of protection to both stator and rotor especially when operating with unbalanced supply voltages.

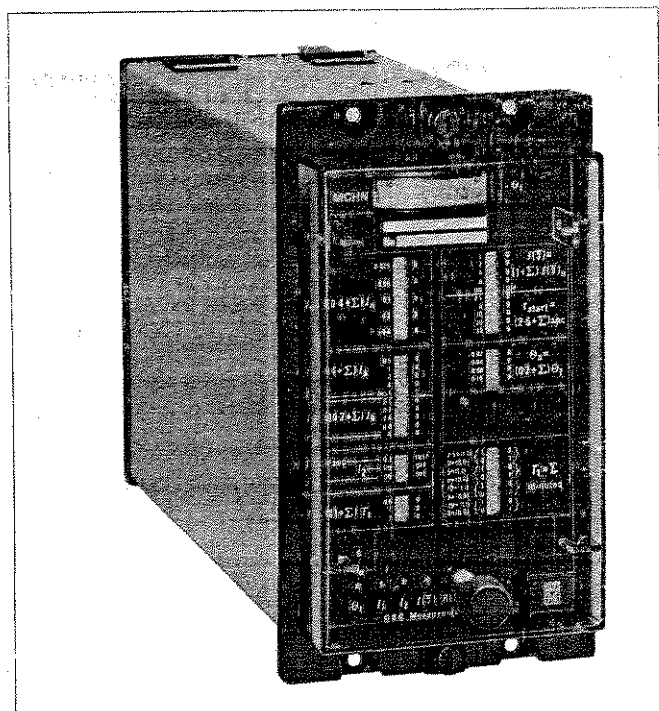


Figure 20.12 Type MCHN motor protection relay.

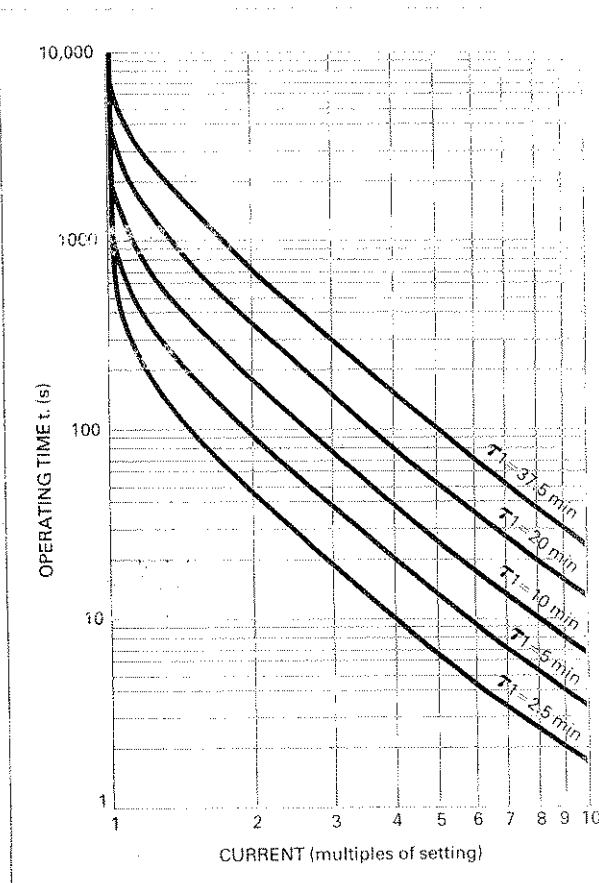


Figure 20.13 Relay MCHN cold thermal characteristics.

The heating of the motor is determined by the equivalent current  $I_e$  which is given by:

$I_e = (I_1^2 + KI_2^2)^{1/2}$  where  $I_1$  and  $I_2$  are the positive and negative sequence currents flowing and  $K$  is a constant allowing for the greater heating effect of one unit of negative sequence current compared with one unit of positive sequence current. The value of  $K$  varies according to the type and construction of the machine, figures of  $K=3$  to  $K=6$  are commonly encountered.

In the MCHN relay the effective relay operating current is  $(I_1^2 + KI_2^2)^{1/2}$ , where  $K$  is adjustable from 3 to 10.

Protection against unbalance or single-phasing conditions is provided by an adjustable, negative sequence, overcurrent detector which initiates a tripping operation after an inverse time delay. By means of an ON/OFF switch provided on the relay front plate this protection may be made operative or not as required.

Short circuit protection is provided by an adjustable high set, overcurrent detector which responds to positive sequence currents. This element may be selected by a switch to trip either instantaneously or after a brief inverse time delay. The latter may be useful when the current setting selected for the element is low enough for it to be operated spuriously by the peak currents which may appear at the beginning of the starting period, from switch closure at the more onerous points on the waveform.

When the relay is applied to a motor controlled by a fused contactor, short circuit protection is normally provided externally by the fuse, so the relay short circuit protection can be switched out of service, as required, by means of a further ON/OFF selector switch on the relay front panel.

Earth fault protection is also included, being energized either from a core balance CT or from a three phase residual CT connection, operation being either instantaneous or time delayed by 0.3 seconds.

Protection for an extended starting time is included, together with stalling protection for motors with stall



withstand times both greater than and less than the motor starting time. For the latter case a tacho-switch signal is required from the motor.

A supervision facility is included to monitor the relay auxiliary voltage supply. Should the auxiliary supply fail the relay thermal replica is retained, with the relay replica continuing to cool at the rate determined by the cooling time constant control  $\tau_2$ , set to correspond to the motor cooling characteristic.

## 20.16.2

### Modular relay type MCHG

The MCHG relay illustrated in Figure 20.14 is designed to provide a good level of protection for low voltage motors at a relatively low cost.

The relay combines analogue and digital techniques and has a wide current setting range (68 to 131% rated current). Also, the resetting time of the relay can be varied to follow the cooling time of the motor, so permitting a restart subsequent to a trip only when the motor is ready for a restart.

All current and timer settings are adjusted by means of switches on the relay front panel. Operation of the relay is indicated by means of two light emitting diodes, one indicating a trip condition and the other indicating that the relay is inhibited until the thermal reset time has expired.

The MCHG is a multi-function relay, which in addition to the basic thermal protection to IEC 255-8, provides unbalance and single phase protection together with sensitive earth fault protection.

The relay can be reset from a remote push button or arranged to be self-resetting by means of an external link.

A test facility is included in the relay: a push button mounted in the relay front panel can be used to prove the relay operation with a simulated overload of  $6 \times I_n$ .

Figure 20.15 shows the MCHG block diagram and basic circuit elements. The motor currents are monitored in two phases, reduced in amplitude by the internal CTs and then converted into voltages proportional to the currents.

This voltage is converted into a series of pulses having a frequency proportional to the square of the voltage.

This signal is combined with a fixed frequency pulse generator. The timing characteristic is determined by a counter which can be adjusted to select the thermal

overload time (at  $6 \times I_n$ ) and the reset time, which is independent of the overload set time.

The output of the counter is gated with a comparator which determines if the signal is above or below setting. This signal then controls a 4 bit counter which in turn controls:

- The transfer from the cold to hot thermal curve and vice versa.
- The transfer from the overload timer to the reset timer.
- Provides an output trip signal.

The single phasing/unbalance characteristic is independent of the thermal characteristic and operates on the principle of the difference in ripple between a three phase balanced signal and that in an unbalanced condition. The output from the detector short-circuits a fixed definite time delay element.

The earth fault element has a separate current input and level detector and is designed to operate from a core balanced CT. The basic sensitivity is fixed, but may be varied in an overall sense by selecting the core balance CT ratio to suit. The earth fault element has an adjustable definite time delay.

Power for the electronic circuitry is derived from a line to neutral connected VT. The output element is an auxiliary attracted armature relay fitted with two change-over contacts and is normally energized under healthy conditions.

In addition to the relay facilities already mentioned, the low thermal overshoot of this type of relay ensures that the relay can be set close to the motor starting time, making it possible for the thermal unit to provide stall protection when applied to a motor having a stall withstand time greater than the starting time.

## 20.17

### ADDITIONAL PROTECTION FOR SYNCHRONOUS MOTORS

#### 20.17.1

##### Pull-out protection

This protection is normally applied to motors which are subject to sudden instantaneous overloads. The value of the overload could exceed the pull-out torque of the motor, causing it to fall out of step. If the field excitation is kept on, the motor stalls, drawing a heavy stator current, and is unable to re-synchronize even if the overload disappears. The pull-out relay is arranged to trip the motor under these circumstances. This is preferred to merely disconnecting the field and allowing the machine to run as an induction motor, because the overload may persist, in which case damage to the motor might result, particularly to the damper windings, from overheating caused by the slip frequency currents.

The relay recommended for the protection of synchronous motors against loss of synchronism is one which is sensitive to the power factor of the stator current. When the motor loses synchronism, a heavy current at a very low power factor is drawn from the supply. The type FOS relay will detect this condition and operate within the first half cycle of slip frequency.

#### 20.17.2

##### Damper winding thermal protection

This protection is sometimes included to protect the damper windings against overheating if prolonged operation out of synchronism occurs after either a pull-out, a prolonged start, or a succession of attempted starts. This protection can be used to replace the total time relay normally included in the starting sequence control circuit, and has the additional advantage over the total time relay of preventing a number of successive starts being attempted.

For this application a thermal relay in the field circuit of the

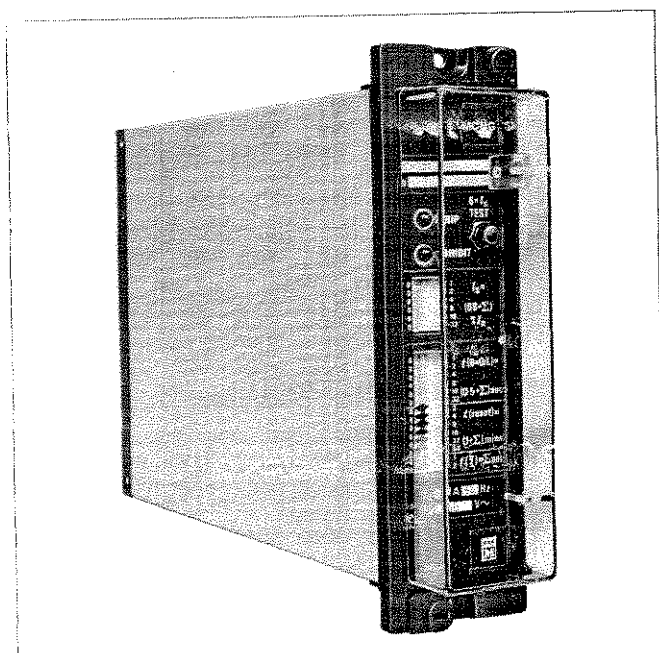


Figure 20.14 Motor protection relay for 3 phase induction motors.

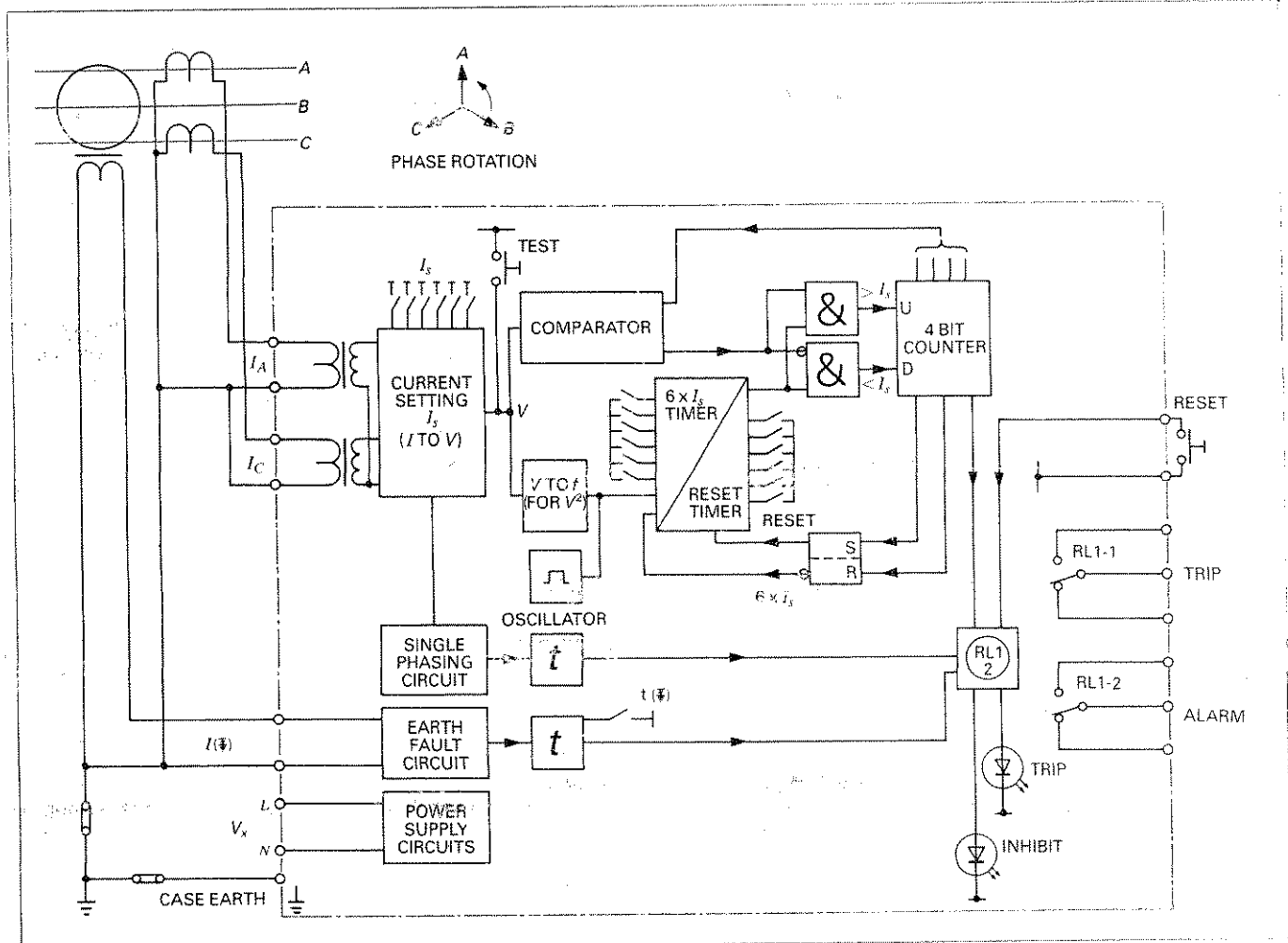


Figure 20.15 Relay type MCHG block diagram.

machine connected in parallel with an inductance is suitable. The current through the relay is proportional to the slip frequency, being greater at high values of slip. By this means graded protection is obtained for the damper windings.

### 20.17.3 Field thermal overload protection

This protection, which consists of a normal thermal overload relay, should be applied to machines which are equipped with automatic field forcing. For such machines, a failure in the field excitation control circuit could lead to a continuous current in the field winding greater than its rating.

### 20.17.4 Protection against sudden restoration of supply

If the supply to a synchronous motor is interrupted, it is essential that the motor breaker be tripped as quickly as possible if there is any possibility of the supply being either automatically restored or restored without the knowledge of the machine operator. This is necessary in order to prevent the supply being restored out of phase with the motor generated voltage.

There are a number of forms of protection available which attempt to guard against this condition; some are preferable to others, mainly according to the motor usage, but none give a completely satisfactory solution to cater for all conditions. The schemes available are described below.

### 20.17.5 Underpower and reverse power protection

These are the usual methods, but they are applicable only

where power reversals do not occur under normal operating conditions.

Underpower protection should be used when there is a possibility of no other electrical load being connected to the busbars on the failure of the supply. If there is always another electrical load connected, a reverse power relay has advantages over the underpower relay, in that it will be more stable in the presence of small power reversals caused by loading conditions. It is necessary to incorporate a slight time delay to overcome momentary reversals of power due to system faults and so on.

If power reversal is possible under normal operating conditions, one of the two following methods or a combination of the two should be used.

### 20.17.6 Overvoltage and underfrequency protection

The overvoltage protection will operate when the supply fails if there is little other load connected to the busbars supplying the motor and there is no load on the motor itself. Under these conditions the voltage could rise instantaneously, because of the open circuit regulation of the machine, which could be of the order of 20–30%.

The underfrequency relay will operate in the case of the supply failing when the motor is on load, which causes the motor to decelerate fairly quickly. The main advantage of these two forms of protection is that they can be instantaneous in operation, making them particularly useful when the supply breaker is equipped with high speed auto-reclosing.

# Rectifier protection

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- 21.1 Introduction.
- 21.2 Mercury arc rectifier protection.
- 21.3 Selection of protective systems.
- 21.4 Semiconductor rectifier protection.

## 21.1

### INTRODUCTION

The mercury arc rectifier has been widely used for a great variety of duties for many years, and as a result the protection applied has been standardized to generally simple and reliable types.

Modern techniques of rectifier design and production now make it possible for the majority of duties to be performed by the semiconductor rectifier. This has brought new demands in control and protective relaying; some of the more common protective relay applications are discussed in this chapter.

## 21.2

### MERCURY ARC RECTIFIER PROTECTION

The types of faults to which mercury arc rectifiers are most prone can be classified into four groups:

- i. Overload and short circuits.
- ii. Backfires.
- iii. Fire-through on grid-controlled rectifiers.
- iv. Ion starvation.

### 21.2.1

#### Overloads and short circuits

Mercury arc rectifiers can usually be operated at loads above their continuous or short time rating without causing immediate structural failure. However, they do have definite limitations, and overload operation could impair and shorten their life.

The rating of a mercury arc rectifier usually includes provision for overloads of a specific magnitude for a given period of time, to take care of service requirements for particular applications.

BS 1968: 1950 recommended the ratings detailed in Table 21.1.

The direct current that can be delivered by a rectifier unit for a dead short circuit across the d.c. output usually ranges from 10 to 20 times the rated value. Its magnitude is determined primarily by the reactance of the rectifier transformer and the source impedance.

Forward current in excess of the specified overload rating up to short circuit values may have some of the following effects:

| Class | Service                                                                                                          | Current<br>(% rating) | Duration                                           | Starting condition for<br>overload rating                         |
|-------|------------------------------------------------------------------------------------------------------------------|-----------------------|----------------------------------------------------|-------------------------------------------------------------------|
| 1     | Light, general or industrial                                                                                     | 100<br>125<br>200     | Continuous<br>5 min.<br>5 s                        | After 6 hr at rated<br>current starting at<br>ambient temperature |
| 2     | Heavier, general or industrial,<br>and light traction duty (for example<br>most tramway and trolleybus services) | 100<br>125<br>200     | Continuous<br>2 hr<br>15 s                         | After 6 hr at rated<br>current starting at<br>ambient temperature |
| 3     | Railway                                                                                                          | 120<br>125<br>300     | Continuous<br>2 hr<br>1 min.                       | After 3 hr at rated<br>current starting at<br>ambient temperature |
| 4     | Railway service where<br>Class 3 is not<br>suitable                                                              | 100                   | Continuous<br>(Overloads as specified in contract) |                                                                   |
| 5     | Heavy electrochemical<br>and so on                                                                               | 100<br>150            | Continuous<br>1 min.                               | After continuous<br>operation at<br>rated current                 |

Table 21.1 Classification of mercury arc rectifiers.

- A rise in the temperature of the anodes and other internal parts.
- The liberation of gases and the impairing of the vacuum.
- The production of high voltage surges due to arc starvation.
- A greater probability of backfires.

### 21.2.2

#### Backfires

A backfire is the failure of the rectifying action that results in the flow of an electron stream in the reverse direction because of the formation of a cathode spot on the anode.

When a backfire occurs, fault current flows from the healthy anodes to the faulty one. If the d.c. circuit to which the rectifier is connected has other d.c. voltage sources, the current flow at the cathode will reverse and fault current will flow from cathode to anode, its magnitude being determined by the inductance and resistance of the fault path.

If there is no feed-back from the d.c. circuit and all the reverse current to the faulty anode comes from the other anodes of the rectifier, the fault current is determined, apart from the arc drop, only by the impedance of the transformer and the source impedance. It usually reaches its maximum value in the first cycle and its magnitude is generally comparable to that of the d.c. short-circuit current.

If not removed immediately, a backfire will produce:

- Pitting of the graphite anodes, thus introducing some contamination into the tank.
- Eventual melting of the grid cages.
- Cracking of the anode insulators.
- Mechanical stresses on the transformer windings.

### 21.2.3

#### Fire-through of grid controlled rectifiers

If the grid of a rectifier is held negative with respect to the cathode, it will prevent the anode from picking up current. However, if for any reason the grid fails to hold off the positive potential, a sudden rise in the d.c. voltage will occur. This is known as a 'fire-through'.

When the connected load is a motor, the greatest overload current will occur at the instant when the grid is fully retarded to give zero voltage and the motor is therefore at a standstill. If the full d.c. voltage is suddenly applied, the fault current is limited only by the motor armature resistance and the regulation of the rectifier equipment.

Fire-throughs may pass unnoticed when there is only a small amount of control, or if one anode fires through and then recovers.

### 21.2.4

#### Ion starvation

When a mercury arc rectifier is first started, the mercury vapour pressure depends on the ambient temperature. Each anode arm contains only enough ions to supply a certain current. Moreover, as ionization takes place, the vapour in the arm expands rapidly and disperses. During this process, which takes place in a few milliseconds, the current builds up and then collapses for lack of ions to support it. This chopping of current, in a highly inductive circuit, induces high surge voltages which are limited only by the transformer winding capacitance.

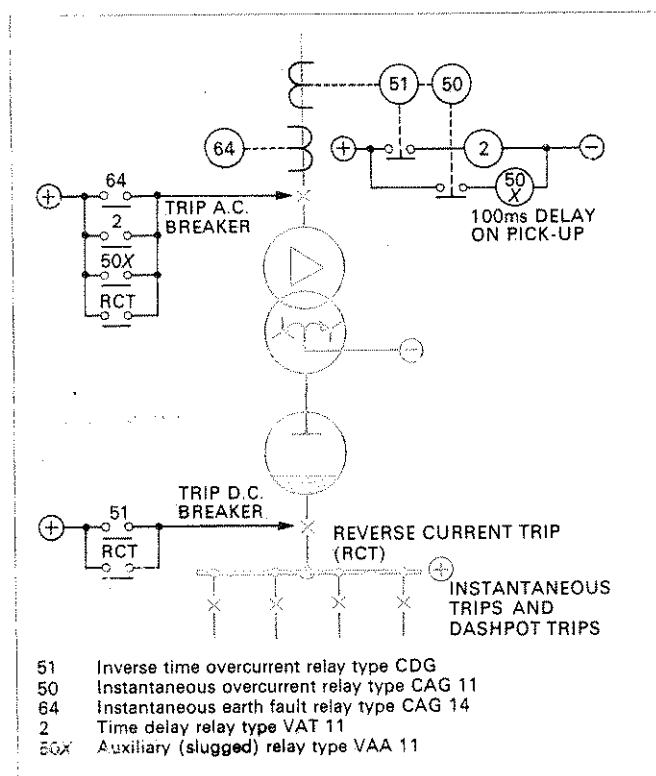


Figure 21.1 Typical protection arrangements for constant voltage mercury arc rectifier.

### 21.3

#### SELECTION OF PROTECTIVE SYSTEMS

The basic protective requirements for a rectifier unit, as shown in Figure 21.1, are satisfied by arranging the a.c. circuit breaker to trip instantaneously when the restricted earth fault protection on the HV side of the rectifier trans-

former operates, and after a time delay for the lower values of overcurrent on the rectifier unit together with instantaneous high set units for the higher values. The d.c. breaker is controlled by an instantaneous reverse current trip or polarized relay. Such equipment is adequate for most applications with a single unit of moderate capacity where the protection of the rectifier equipment is the primary consideration.

Where continuity of d.c. supply is essential, anode circuit breakers capable of opening and automatically reclosing the faulty anode are generally used.

To ensure the maximum protection without sacrificing continuity of service, the protective system must possess a high degree of selectivity. Faults can generally be classified as internal or external. In the ordinary rectifier installation, the most common internal fault is the backfire. External faults are usually short circuits of varying severity on the connected d.c. system or internal faults in parallel units.

For a unit operating alone, the a.c. system currents during a backfire or during a solid d.c. short circuit are of the same order of magnitude. Selectivity between a.c. and d.c. circuit breakers is obtained by the use of inverse time and instantaneous overcurrent trips. In general, the more units there are in parallel, the easier it is to obtain good selectivity, since each unit will contribute less to an external fault.

Because the backfire is the most serious fault to which rectifiers are prone, instantaneous overcurrent devices are set as low as operating conditions will allow, usually four times full load. The inrush current of the rectifier transformer is generally the limiting factor. Selectivity is lost, however, if the d.c. fault results in an alternating current exceeding the setting of the instantaneous overcurrent device. This is usually avoided by interposing a slight time delay (5 cycles) which allows the d.c. breaker to trip.

When anode circuit breakers are used, extremely good selectivity can be obtained by inserting inverse current trips in the anode circuits. However, in the absence of anode circuit breakers and where the d.c. system produces feed-back during backfires, a reverse current trip on the d.c. circuit breaker can often be employed to provide excellent selectivity. If the reverse current device is arranged to trip the a.c. circuit breaker, backfires can be cleared very quickly.

Arc suppression can sometimes be used in grid-controlled rectifiers to suppress the a.c. component of backfire. A negative voltage is applied, usually by electronic means, between each grid and cathode. The faulty anode and the anodes feeding into it continue to fire, but the others are suppressed. As the anodes feeding into the fault reach zero current the grids gain control. In this way the fault can be suppressed in one cycle. A high speed d.c. breaker must be used to cut off the d.c. feed-back. The arc suppression can be actuated by current derived from current transformers, in which case it will operate on heavy overloads as well as backfires. Alternatively, a differential circuit can be used, in which the a.c. input and d.c. output currents are compared. Only on backfires during which the d.c. current falls to zero or reverses will the device operate. The differential scheme should be used wherever a number of rectifier equipments are connected in parallel.

## 21.4

### SEMICONDUCTOR RECTIFIERS AND PROTECTION

In general semiconductor rectifiers have proved more reliable in service than their mercury arc counterparts; the types of faults\* to which they might be subjected are classified as follows:

- i. Cell overloads and failures.
- ii. Operational faults such as backfires and so on.
- iii. D.c. faults on the busbar and cable.
- iv. A.c. faults on the supply cable, transformer and so on.

#### 21.4.1

##### Overloads

The overloads to which monocrystalline (silicon and germanium) semiconductors may be subjected are broadly categorized in BS 4417:1970 as shown in Table 21.2.

Because of their low thermal mass and their consequent low fault current withstand, the cells or strings (combination of cells) in the rectifier stack need to be individually protected; Figure 21.2 shows a typical three-phase bridge circuit giving six pulse rectification, and its associated fuse protection.

Depending on the duty to be performed by the bridge, each

| Class | Duty                             | Current (% rating) | Duration                     | Starting condition for overload rating      |
|-------|----------------------------------|--------------------|------------------------------|---------------------------------------------|
| A     | Electrochemical processes        | 100                | Continuous                   | —                                           |
| B     | Electrochemical processes        | 100<br>150         | Continuous<br>1 min.         | After continuous operation at rated current |
| C     | Industrial service               | 100<br>125<br>200  | Continuous<br>2 hr<br>10 s   | After 6 hr operation at rated current       |
| D     | Industrial service               | 100<br>125<br>200  | Continuous<br>2 hr<br>10 s   | After continuous operation at rated current |
| E     | Medium traction and mining       | 100<br>150<br>200  | Continuous<br>2 hr<br>1 min. | After continuous operation at rated current |
| F     | Heavy traction                   | 100<br>150<br>300  | Continuous<br>2 hr<br>1 min. | After 3 hr operation at rated current       |
| G     | Duty cycle agreed with purchaser |                    |                              |                                             |
| H     | Light industrial service         | 100<br>150<br>200  | Continuous<br>1 min.<br>10 s | After 6 hr operation at rated current       |

Table 21.2 Classification of semiconductor rectifiers.

\*See also *The Characteristics and Protection of Semiconductor Rectifiers*. D. B. Corbyn and N. L. Potter. I.E.E. Paper No. 3135 U November 1959.

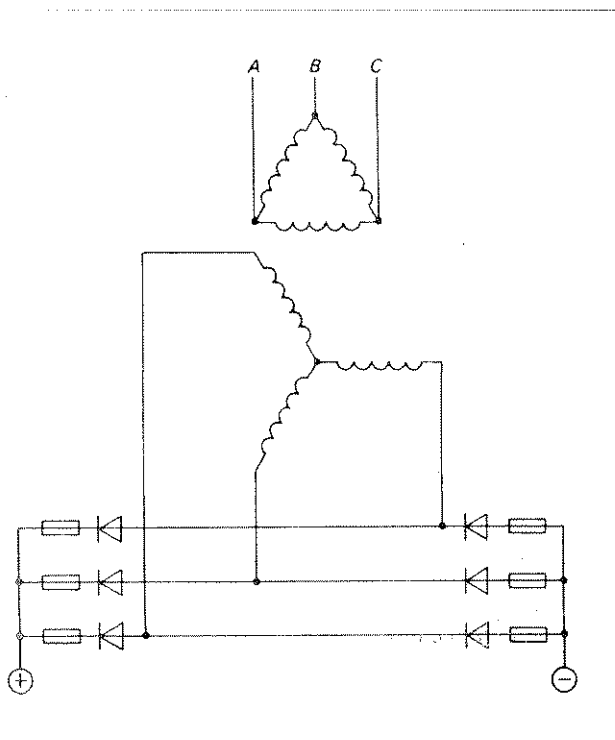


Figure 21.2 Typical three-phase bridge circuit.

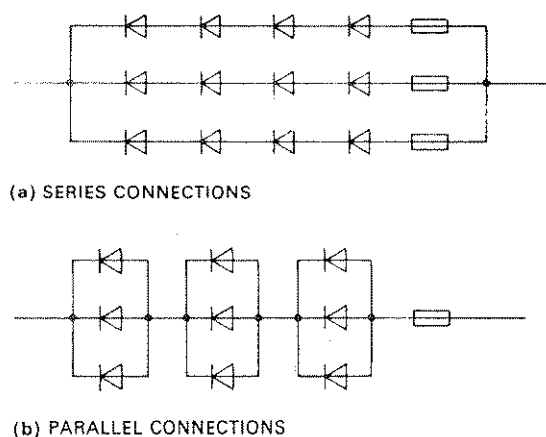


Figure 21.3 Series and parallel connections of rectifier cells.

phase arm could comprise series or parallel strings, as illustrated in Figures 21.3(a) and 21.3(b). For continued operation after the failure of an individual cell, the cell strings must be carefully graded so that the remaining cells can withstand the increase in reverse voltage or additional overload, depending on the string configuration.

For the lower rated equipment, the blowing of an individual cell fuse is made to trip the whole equipment, as, with only a small number of parallel or series cells, severe over-rating can occur. In the larger installations, with many cells per string, a mere warning of failure may be adequate, leaving the cells to be replaced when convenient.

The fuses used for the protection of the cells are normally the indicating striker pin type, used either for primary fusing or connected across a fused group. When the main fuse clears, current is diverted through the small fuse and melts its element. This causes a spring to eject a small striker pin, which operates a micro-switch to trip the equipment or give an alarm.

## 21.4.2 Overvoltage

Rectifier cells can fail because of an overvoltage, which may be caused by switching or lightning surges, arc voltages on fuse clearance, chopping of load current or the physical phenomenon of hole storage. Surge diverter and special capacitance resistance networks are employed to safeguard the cells against such overvoltage, as shown in Figure 21.4.

## 21.4.3 Backfire faults

Internal faults such as the backfire of a rectifier cell, as well as external faults, can cause overcurrents in healthy cells, and must be cleared immediately to prevent further damage.

When a rectifier cell fails to withstand the reverse voltage, that is, if it backfires, at the end of its conduction period, it becomes short-circuited. Figure 21.5 shows a three phase bridge in which rectifier 1 has failed at the end of its normal conduction period. This imposes a line to line fault on the transformer, for part of the rectification cycle, via rectifier 3. Rectifier 5 provides another path to produce a three-phase fault for a further part of the cycle.

These faults produce the highest peak currents and require either that the busbars and transformer windings shall be mechanically strong enough to withstand the forces involved or that the protective device, that is, the fuse, shall limit

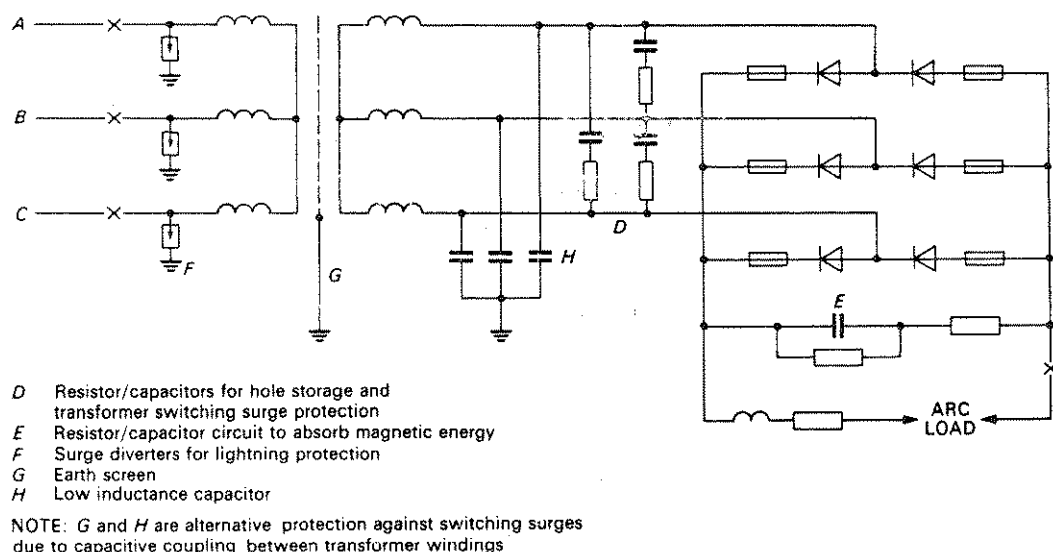


Figure 21.4 Methods of surge voltage protection.

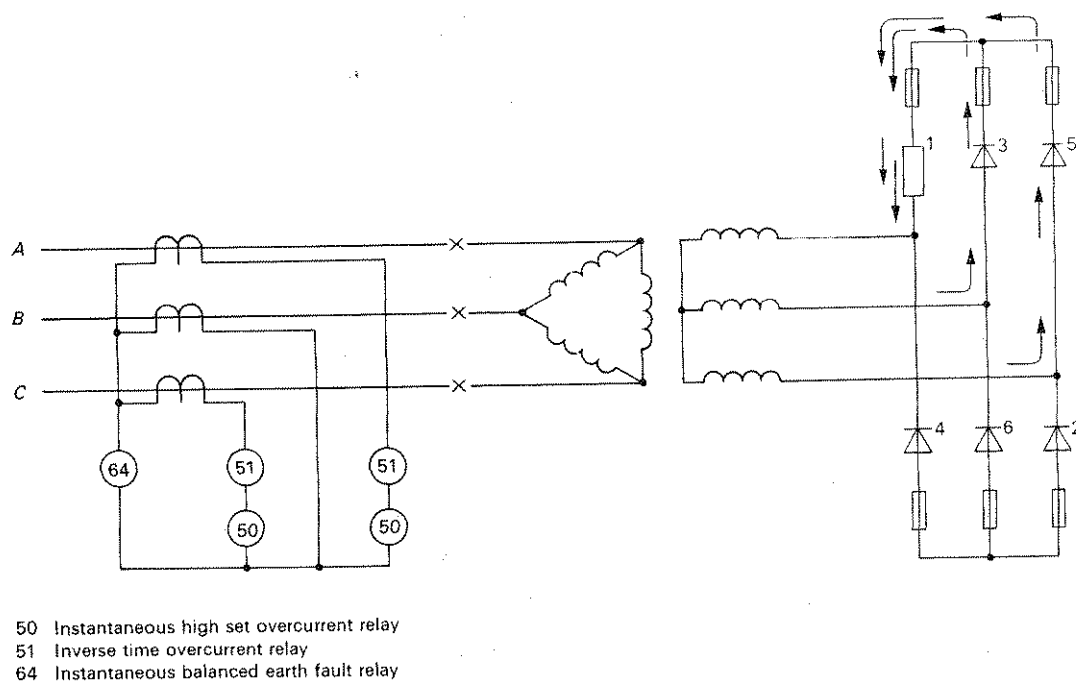


Figure 21.5 Backfire fault condition in one arm of a three-phase bridge.

the fault current. Semiconductor rectifiers require that the fault be removed in about 5 ms to prevent the fault spreading. This ensures that the prospective peak currents never flow in practice.

#### 21.4.4 HV overload

To protect against HV feeder-transformer faults and to act as back-up against overload, protective relays may be applied as illustrated in Figure 21.5 on the HV side of the transformer. Where individual fusing is not applied, this may be the main form of overload protection and will consist of inverse time overcurrent elements with instantaneous high sets; an extremely inverse characteristic would be the most suitable of those available with electromechanical time delayed overcurrent elements. Instantaneous earth fault protection can also be applied if the transformer winding configuration is as shown.

The use of transistorized circuitry in modern relays allows a far more inverse time/current characteristic to be obtained, enabling the semiconductor overload capability to be matched closely. An additional benefit of using static relaying comes from its capability of resetting instantaneously, allowing it to be used in peaky and cyclic loading conditions. The conventional disc overcurrent relays tend to have a relatively long reset time, which could allow the summation of this type of load, eventually causing unnecessary tripping.

# The application of microprocessors to substation control

- 22.1 Introduction
- 22.2 Microcomputer systems
- 22.3 Microcomputers
- 22.4 Microprocessors
- 22.5 Program memory
- 22.6 Temporary memory
- 22.7 Input-output
- 22.8 Noise and interference
- 22.9 Software
- 22.10 Application orientated languages
- 22.11 PERM 200 hardware
- 22.12 Applications of PERM
- 22.13 Auto-reclosing
- 22.14 Event logger
- 22.15 Voltage control
- 22.16 Self-testing

## 22.1

### INTRODUCTION

In recent years the words microchip and microcomputer have become everyday terms to professional engineers and laymen alike. These devices are being increasingly applied in the consumer, commercial, industrial and military fields.

Development of the technology continues unabated such that it is difficult to see areas which will not be affected.

Early on it was appreciated that it would have growing application in the field of control and protection of power systems. GEC ALSTHOM Measurements introduced a general purpose microcomputer system in 1974. Known as PERM, an acronym for Programmable Equipment for Relay-ing and Measurement, the system has been used widely in power system applications including automatic switching, event recording, voltage control, sequence control, tele-control, and several areas related to energy metering. In 1979 an upgraded version of this equipment known as PERM 200 was introduced, to take advantage of technology advances.

In this chapter the hardware, software and application areas of this equipment are outlined, but before this, the main aspects of microcomputer technology are summarized.

## 22.2

### MICROCOMPUTER SYSTEMS

Figure 22.1 depicts a general purpose microcomputer system in which the microcomputer performs a monitoring and/or control function on the plant. Depending on the nature of the task some or all of the other functions may be required: interaction with an operator, often via a visual display unit (VDU) and 'hard copy' from a printer; a bulk memory when large amounts of data must be stored and communication with remote points possibly by telephone lines. The hardware of such a system could have many similarities, be it, for example, in a power system, process control plant or automatic laboratory. Furthermore, the programs which define the operation of the system could also have many common aspects although some would be specific to the type of plant under control.

Computers have been used in control applications for a number of years. They give advantages of greatly increased versatility and flexibility and in sophistication of control; these arise out of their programmability. The more recently developed microcomputer has added significantly to their reliability and economy, both of which are a product of



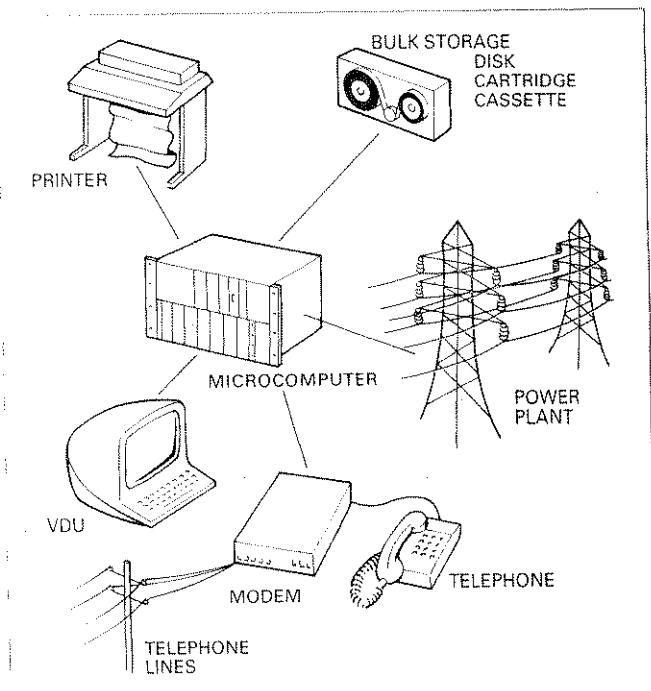


Figure 22.1 Microcomputer system.

their use of large scale integrated (LSI) circuits: the reliability because of the reduction of the numbers of components and interconnections and the economy because of their volume production.

### 22.3 MICROCOMPUTERS

Figure 22.2 is a block diagram of a typical microcomputer. It consists of four areas: the microprocessor, the program memory, the temporary memory and the input/output interface. The four elements are usually interconnected by a number of signal lines which include data, address and control lines, referred to as the microcomputer bus. The amount of memory (expressed in bytes) and the nature of the input/output interface depends very much on the application for which the equipment is used. Indeed, there are two main strands of development: in one the semiconductor manufacturers place all four elements on a single chip, and in the other individual chips are designed for each area and these are made as powerful as the technology allows. The single chip microcomputer is used in simpler, lower cost products, for example washing machine controllers or, to be relevant to the present discussion, in basic protective relays. The general purpose microcomputer is used in the more complex areas, for example, where the hardware and software may need a significant amount of tailoring to meet the requirements of a particular application.

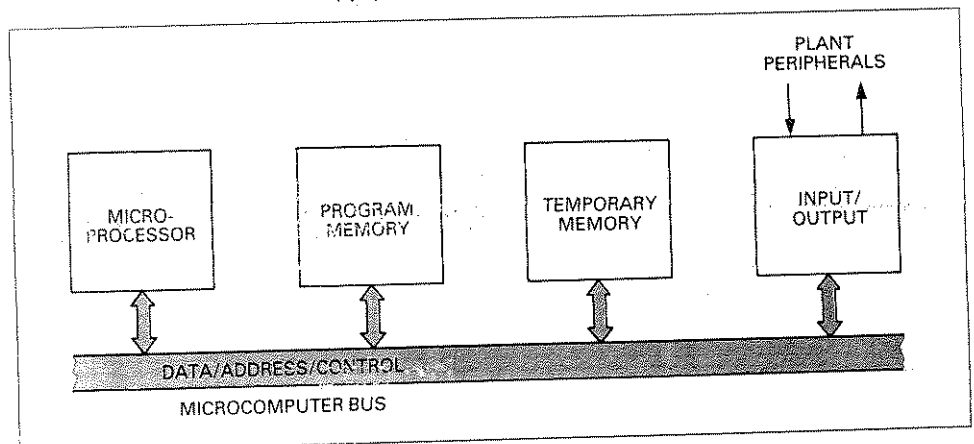


Figure 22.2 Microcomputer block diagram.

## 22.4 MICROPROCESSORS

These may be considered as the intelligent part of microcomputers. They have the ability to carry out a number of quite simple operations such as arithmetic, logic, data transfer, storage, control and 'branching', which is the ability to decide between alternative courses of action dependent upon programmed criteria.

The operations constitute the 'Instruction Set' of the microprocessor. A simplified view of a microprocessor architecture represents it as having an arithmetic and logic unit (ALU), a register array, a control unit and ports by which it is connected to external circuits. Basically the microprocessor operates by manipulating binary data: fetching data from outside, performing operations on it in the ALU, and transferring it between its registers or to the outside. The 'heartbeat' of the device is provided by a crystal oscillating at a frequency of a few MHz, which enables the microcomputer to perform simple operations very rapidly. The high frequency clock is divided down into time states, cycles and instructions during which basic internal operations, in-out data transfers and complete instructions are carried out. Programs are instructions performed or executed in a defined sequence stored in the form of binary codes in the program memory.

### 22.5 PROGRAM MEMORY

In a typical industrial application the program of a microcomputer, once commissioned, is unlikely to change appreciably over the course of several years. Therefore it is vitally important that the codes are held securely and are not subject to corruption, for example if the supply is lost or by electrical noise. The currently favoured devices for this task are EPROMS, Erasable and reProgrammable Read-Only Memories. In normal operation the program codes are read from the units by microprocessor. However, the writing in of these codes is quite separate and is carried out using a 'Programmer' unit.

Once programmed the data is held permanently but can be erased by exposing the chips to high intensity ultra-violet light through a window in the integrated circuit. This is important during the development phase when changes take place.

### 22.6 TEMPORARY MEMORY

The execution of a program results in data which must be stored temporarily. So, unlike program memory, the temporary memory is both read from and written to in normal operation and is sometimes known as 'read-write' or random access memory (RAM). Semiconductor RAM is volatile, which means that the stored data is lost when the supply is lost.

## 22.7 INPUT-OUTPUT

The input-output interface circuits transform the variety of signals coming from the external environment into the form acceptable to the microcomputer, and vice-versa. For example, inputs may include two-state signals from relay contacts, analogue values from instrument transformers or transducers and serial binary data from communication links and peripheral devices. Outputs may include two-state relay contact outputs, analogue outputs to meters or controllers and serial binary outputs to communication links or peripheral devices. Serial links will usually have characteristics selected from alternatives for protocol, for example, synchronous or asynchronous; electrical interfaces; speed of operation, in terms of data rate.

For each of the above categories a variety of integrated circuits including LSI circuits is available. When assembled together in a suitable enclosure which includes power supplies, powerful cost-effective equipment can result.

In addition a wide variety of peripheral devices including visual display units, printers and bulk storage devices such as magnetic cassettes, cartridges and discs are available which can be interfaced to the microcomputers in a straightforward manner.

## 22.8 NOISE AND INTERFERENCE

In Section 7.6 this subject is discussed with respect to static relays containing solid state components. It can be argued that digital microelectronic circuits are even more susceptible to damage caused by surges because of their lower power ratings and to maloperations because of their wide operating bandwidths up to several MHz. Therefore it is necessary to employ a variety of techniques to combat this, including surge suppression, filtering, isolation of input-output signals, screening and segregation of sensitive circuits. The IEC high frequency disturbance tests are appropriate for testing this type of equipment.

## 22.9 SOFTWARE

The basis of the software is the instruction set of the microprocessor which, together with the memory and the input-output, can be represented as a software model, the basis on which microcomputer programs can be written. There are two levels of programming language: low and high.

The low-level or 'Assembler' language is directly related to the instruction codes of the microprocessor which are represented by mnemonics such as MOV C, B; MVI M; ADD A; XRA L; JMP and IN. The advantages of the assembler language are that programs written in it require the minimum storage and have the fastest execution time. However, it is applicable only to a particular type of microcomputer and requires a detailed understanding of its operation.

High level languages are virtually independent of a particular microcomputer and can therefore be written more easily. However, they may be less flexible, use more memory and execute slower than the assembler language. Examples are FORTRAN, COBOL, CORAL, APL, BASIC, PL/M, PASCAL and 'C', several of which are popular for microcomputer use.

The programs written in these languages must be translated into the object code of the microprocessor. This is done using other computer programs. For assembler and high level languages these are known as assembler and compiler programs respectively. They may run on the microprocessor itself (the 'target') or on a separate machine (the 'host'), for example, a data processing computer, in which case they are termed cross-assemblers or cross-compilers.

## 22.10 APPLICATION-ORIENTED LANGUAGE

These are aimed at the programmer who is familiar with a particular application area rather than with computer languages. They are usually specific to a particular range of problems such as logic systems (programmable logical controllers) or to controlling continuous processes (for example, chemical), but they make program writing in these areas relatively simple.

Such languages require three parts for their implementation: an application program, a data base and an editor program. The application program may be thought of as a system which understands all the basic rules relating to the field of application; it knows how to handle the various types of inputs and perform the necessary manipulations to give the desired results. It should be remembered that the computer is likely to be controlling a number of virtually independent tasks simultaneously and has to be able to allocate time and resources to each one as required. This may need an 'interrupt driven', priority structured operating system to give the necessary speed of response. In this arrangement the normal sequence in which the microprocessor carries out its operations may be interrupted by an over-riding command, to give a particular sub-routine immediate attention. Having completed this interrupt routine, the microprocessor then resumes the normal sequence.

The application program is general and must be given specific details of the system it is controlling, for example, the configuration of the plant and the sequences of events which are to take place. This data is contained in the data base and is accessed by the application program in order to define the procedures that will be followed to carry out the desired tasks.

The editor program allows the programmer to enter the information which goes into the data base. It prompts and accepts commands entered say on a VDU keyboard, in the application language. It may possibly perform some pre-processing and error checking before loading up the data base. The editor program may also have facilities for running and monitoring the system, which is useful in the development phase, but will probably not be necessary during normal operation.

These programs may themselves be written in the assembler or a high level language or a mixture of the two, as is appropriate. Certainly the more time critical areas are likely to be in the assembler language.

## 22.11 PERM 200 HARDWARE

The construction of the PERM 200 hardware is based on the 483mm (19 inch) wide rack or panel mounted modular system shown in Figure 22.3. Figure 22.4 is a block diagram in which each box represents a module in the PERM 200 range. Equipments supplied to meet particular applications contain an appropriate selection from this range.

The modules usually consist of single printed circuit boards which plug into edge connectors in the rear of the subrack. Many of the components mounted on the boards, including all semiconductor devices, undergo quality control tests in order to ensure that the completed equipments achieve good reliability levels, as has been described in Section 7.7.

The hardware is divided into four classifications:

- a. microcomputer
- b. primary interface
- c. secondary interface
- d. power supplies

The following sections outline the more important aspects of these areas.

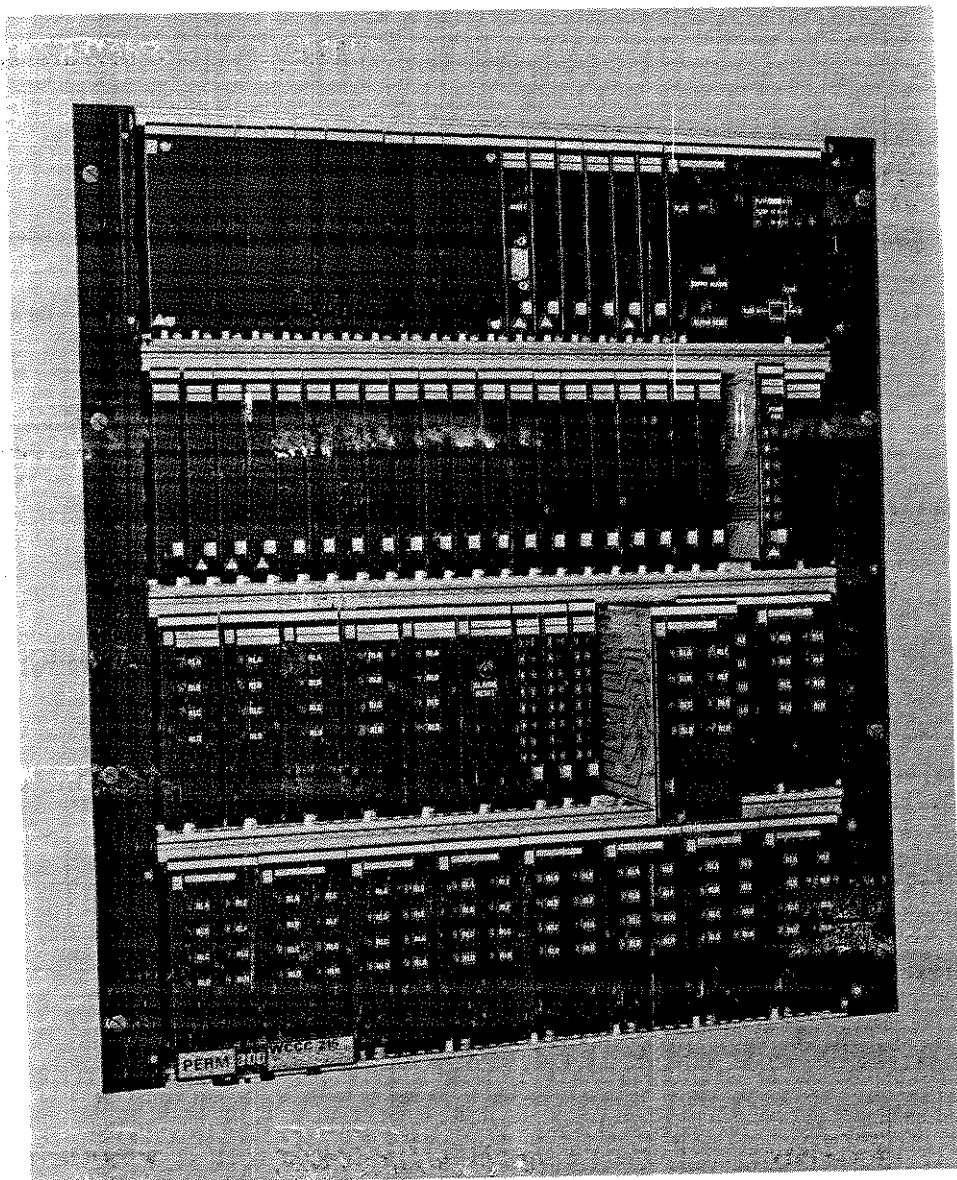


Figure 22.3 PERM 200 equipment for delayed auto-reclose application.

The microcomputer section includes the 'Central Processor' module (CPM). This is the core of the PERM 200 and it exercises control over the other units. It is based on the 8085A microprocessor which has a direct addressing capability of 64k bytes of memory and a cycle time of  $1.74 \mu\text{s}$ . The module also includes a 32 bit timer/counter and a serial communications channel with a program selectable baud rate. This channel, which can be connected via a socket on the module frontplate to a terminal, provides a convenient means of hardware and software testing.

The CPM communicates with the other microcomputer modules over the 'Microcomputer Bus'. This consists of a number (typically 6) of DIN edge connectors mounted on a p.c.b. near the rear of the subrack. Corresponding pins are interconnected to provide a 64 way highway which includes power, address, data and control busses.

Memory modules include a standard type which can store both program and temporary data. It contains storage capacity for up to 48k bytes that may be either EPROM or RAM in any appropriate combination. In this way all the memory directly addressable by the processor is contained in one module.

In some applications large amounts of memory are used for holding data. Such an instance is an event logger which requires non-volatile storage of the text information used in event message printouts. The Electrically Erasable and

reProgrammable Read-Only Memory (EEPROM) module holds up to 16k bytes of electrically erasable read-only memory. Such modules can be combined into memory systems with capacities of up to 512k bytes. Addressing is carried out indirectly using input/output instructions.

The 'Switch' memory module uses miniature dual-in-line switches for storing up to 16 bytes of data. Holding the values of 'dead' timers in auto-reclose applications is a typical use of this module.

In general, microcomputer modules use large scale integrated circuits where possible, supported by low-power Schottky transistor transistor logic (LSTTL) devices.

The input-output (I/O) interfaces are the circuits by which the microcomputer is connected to the external peripherals and plant. This has two levels: the nearest level to the microcomputer is the 'Primary' interface. In this section the I/O 'Buffer' module effectively extends the microcomputer bus to the front of the primary interface where it becomes the input/output bus through which the I/O data, address and control signals are connected to the primary interface modules. These include the 'Input' module which interfaces up to 32 digital (two-state) inputs, the 'Output (Relay)' which has eight miniature relays suitable for alarms and indications, the 'Output (Static)' which has 16 circuits for driving relays (in the secondary interface) and the 'Combined I/O' module which has eight inputs and

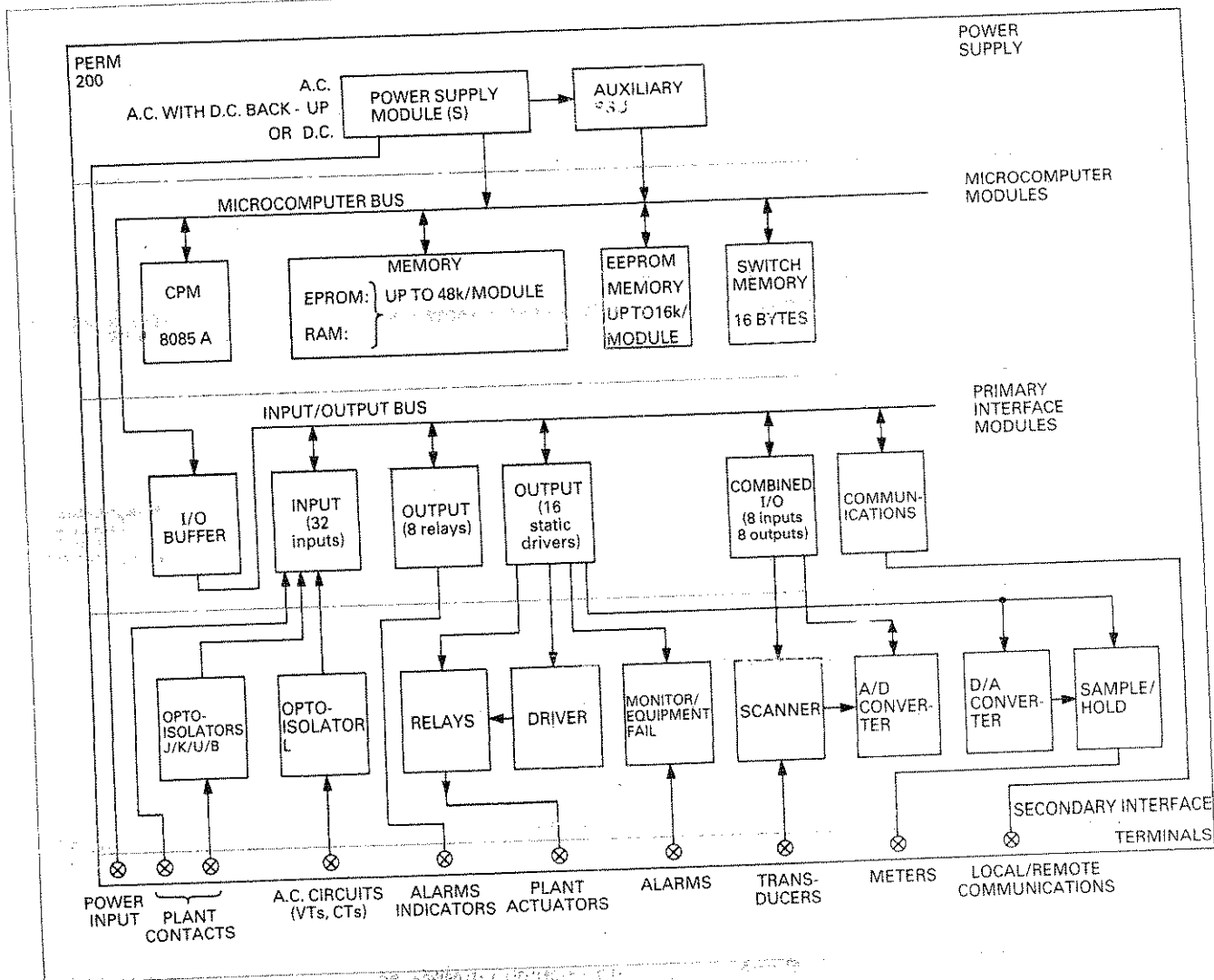


Figure 22.4 PERM 200 block diagram.

eight outputs similar to the input and output (static) modules respectively.

The final module is for 'Communications'. This provides a serial communications channel which can be used for the standard type of asynchronous link to terminals, visual display units and printers or for synchronous links as used in telecontrol. The baud rate can be set by software to be between 110 and 4800 bauds.

In general primary interface modules include some measures to increase noise immunity including filters, surge suppressors and CMOS integrated circuits where possible.

The second level of I/O interface, the 'Secondary' interface modules, provide signal conditioning including circuits which protect against the hostile electrical environment.

Digital inputs from switchgear auxiliary contacts or protection are usually brought in through opto-isolator circuits as shown in Figure 22.5. These consist of a light emitting diode and a photodetecting transistor within a single integrated circuit-like package. By means of optical coupling the current flowing in the diode produces a proportional current in the transistor. Because the coupling capacitance between the two is very small, a few pF, these devices are very effective in blocking interference signals. The 'Opto' J, K, and U modules contain 12, 12 and 8 such circuits respectively. Because the opto-isolator is also a rectifier it can be used where a.c. level detecting without transformers is required, for example, 'Line volts present/not present', as in the Opto-L module. The Opto-B module contains two bistable circuits with opto-isolated set and

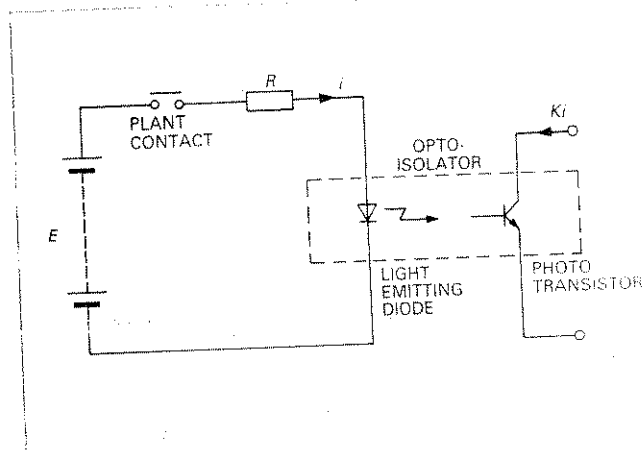


Figure 22.5 Opto-isolator.

reset inputs and can be used to store state information such as 'Auto-reclose In Service'.

Digital outputs are usually taken out through contacts of relays mounted in 'Relay' modules. The standard relay used is a miniature type with two change-over contacts rated at 5A (make and resistive break) which can be used to operate switchgear actuating mechanisms directly or through external auxiliary relays.

The 'Driver' module can be used to drive these relays where large numbers are used, to supplement the output (static) primary interface modules.

In some applications it may be required to input analog signals. Typically these may be derived from transducers which convert primary voltages, current, power, phase angle, and so on, to the standardized form 0–10 mA d.c. An analog data acquisition system is used to perform this function and consists of 'Scanner' modules, each able to scan 16 channels, one at a time, and an 'Analog to Digital Converter' module of 10 bits resolution.

Similarly, analog output signals may be required from the microcomputer to drive indicating meters, for example. The function is carried out by the 'Digital to Analog Converter' module, followed, where a number of separate channels are needed, by 'Sample and Hold' modules, each of which has eight output channels.

The 'Monitor' module is used as a 'Watch-dog' or self-checking unit for the equipment. Under healthy conditions it receives regular pulses from the microcomputer. Should failure occur either as a program malfunction or as a program detected condition then this circuit will trip. Its output drives the 'Equipment Fail' relay module which also trips. The output contacts on this unit are used for indication and interlocking to prevent external maloperation.

'Power Supply' modules can be either d.c. or a.c. or a.c. with d.c. back-up.

Power consumption of the equipment is usually between 15 W and 40 W depending on its size. For good efficiency, switching regulators are used and the units have over-voltage, undervoltage and overcurrent protection.

## 22.12

The PERM equipment has been used in a number of applications within the power system, some of which are discussed in later sections. Where it has been applied to areas for which electromechanical equipment was used, for example auto-reclosing, there have been significant improvements in performance and reliability. Other advantages are flexibility, reduction in size and panel wiring, and reduction in power consumption.

As an example of size reduction, the relay auto-reclose system for a typical four-switch mesh substation, as shown in Figure 14.9, would need four cubicles of equipment, whereas the equivalent microcomputer scheme would occupy a rack mounting 19 ins. wide and only approximately 20 ins. high. The latter also has the advantage of reducing on-site wiring and facilitates the testing of the complete scheme in the factory before installation, so reducing commissioning time.

## 22.13

In this application the microcomputer performs what has usually been performed by electromechanical relays and timers in the more conventional schemes described in Chapter 14.

The microcomputer will perform the auto-reclosing and check the information being received from the substation. The following are examples of this:

The complementary auxiliary contacts from a circuit breaker are checked under normal conditions and will be either 'open' or 'closed'. If they should appear as both 'open' and 'closed' or neither 'open' nor 'closed' an alarm is generated after a short time interval which is introduced to allow the breaker to pass through the transient state of opening or closing. This time interval is typically set to 2 seconds. When applied to isolator contacts the time interval is increased to 40 seconds to allow for the slower transition.

A further check, concerning voltages on the mesh, may be carried out by means of a program which builds up a model of the voltages on the part of the mesh in service. The

presence or absence of voltage on each part of the mesh, as deduced from the model, is then compared with the signals of voltages actually present, and if a difference is found an alarm is initiated. A disparity alarm will be given if a VT fuse is blown.

These checks are to increase the availability of the system to perform auto-reclosing when required, which is likely to be infrequent. For example, an alarm will be raised immediately when a VT fuse or plant auxiliary contact fails, so if possible enabling the fault to be rectified before the equipment is required to perform its function.

Checks are carried out on plant while a reclosing sequence is performed. As each item is initiated to operate, for example, a circuit breaker to close, an isolator to open, a check is made that the item does in fact operate as intended.

This will give an immediate indication as to why a reclose sequence may have failed, and if a sequence is being held for a transient alarm state, for example low air pressure on a circuit breaker, an alarm is generated to indicate why the sequence is being held.

All the above checks are carried out by means of software which can be added to the control sequence software, without requiring additional interfacing hardware.

### 22.13.1

#### Scheme software

Few auto-reclose schemes involve identical plant configurations and control requirements, so the flexibility software offers is highly desirable. However the cost of software is increasing whereas the cost of microcomputer hardware is stable or decreasing. It is therefore not practical to write a new application program for each scheme, as otherwise a microprocessor-based scheme would cost more than a conventional relay scheme. A solution has been to devise a set of standard software modules which can be adapted and linked together to perform a complete control scheme.

This software falls into two main parts, the plant item control programs and the scheme organization program. The latter is responsible for defining the substation arrangement, that is, the connections between items of plant, and the former is the set of programs which will control a particular item of plant such as a circuit breaker or motor-driven isolator.

To produce a reclose scheme for a given substation the first step is to split the substation theoretically into its component parts (circuit breakers, isolators) and interconnecting points (busbars, transformer, lines), as indicated in Figure 22.6.

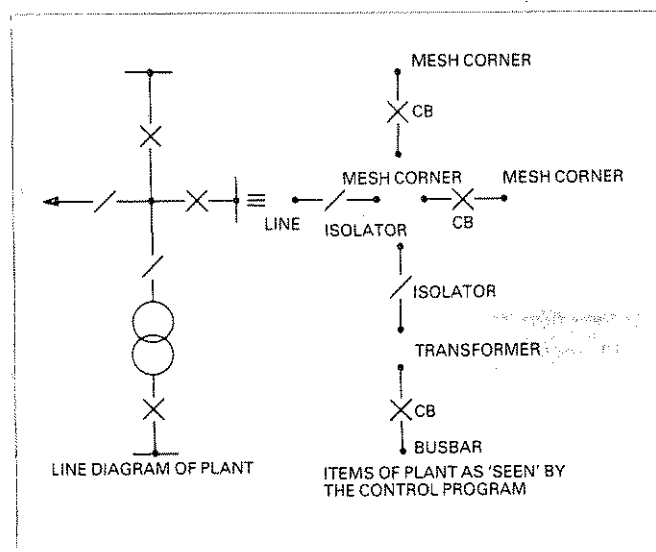


Figure 22.6 Substation reclose scheme.

The substation layout is now depicted in a simplified way which enables the software to be concentrated on the control of individual items of plant. It 'sees' the connecting points (nodes) only as sources of protection and VT signals. So a line will appear solely as a source of transient and persistent protection signals and a transformer will appear only as a source of persistent protection signals. Using this approach it is possible to consider each item of plant independently, without reference to any other item of plant, and by using detailed information about each connecting point or node determined by posing questions such as 'Is there a protection operation?'—'Is there a VT signal present?'—'Is this point In Service?'.

The main organization program then executes each control program with reference only to its particular plant inputs and outputs and the information at each extremity of the item. The control programs are executed sequentially, each one taking a few milliseconds to complete, an interval so short as to give the appearance of parallel processing, as the complete sequence will run in less than 100 milliseconds.

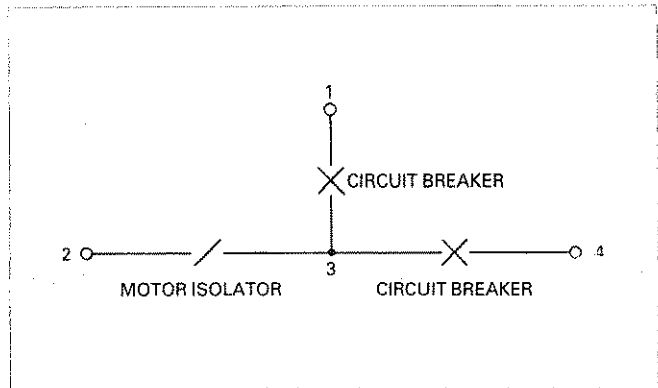


Figure 22.7 Example of breaker and isolator circuit.

So for the sample circuit shown in Figure 22.7, the main program will first execute the motor isolator program by referring to nodes 2 and 3, then the circuit breaker program referring to nodes 3 and 4, and then will repeat the circuit breaker program but this time referring to nodes 1 and 3.

Using this method it is possible to build up any substate arrangement which contains the given control elements.

Software to perform the necessary functions has the auto-reclosing features described in Chapter 14; a block diagram of this method is shown in Figure 22.8.

## 22.14

When used as an event logger the microprocessor records the events which take place, by monitoring the status of auxiliary contacts of both the main plant and the protective relays.

A typical application of this is in unmanned transmission substations. When changes of state occur, a print-out is provided on a local printer detailing the date, time and point of occurrence. Any event taking place whilst the printer is operating is automatically stored and subsequently printed.

An internal 'real-time' clock controls the scan period and the time of operation is logged against each message to provide a comprehensive record of system disturbances. This record may be used to assess the performance of protection and main plant and also facilitates post-fault analysis. A typical teletypewriter print-out is shown in Figure 22.9.

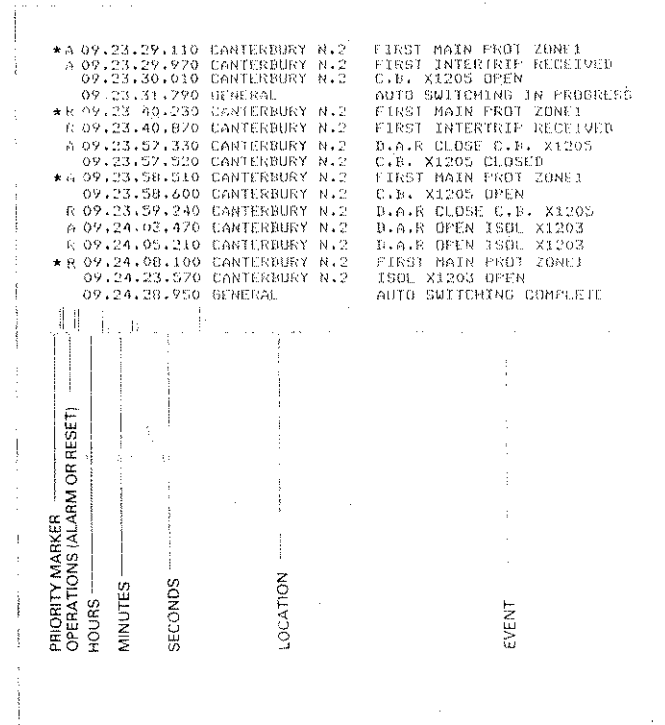


Figure 22.9 Typical event logger print out.

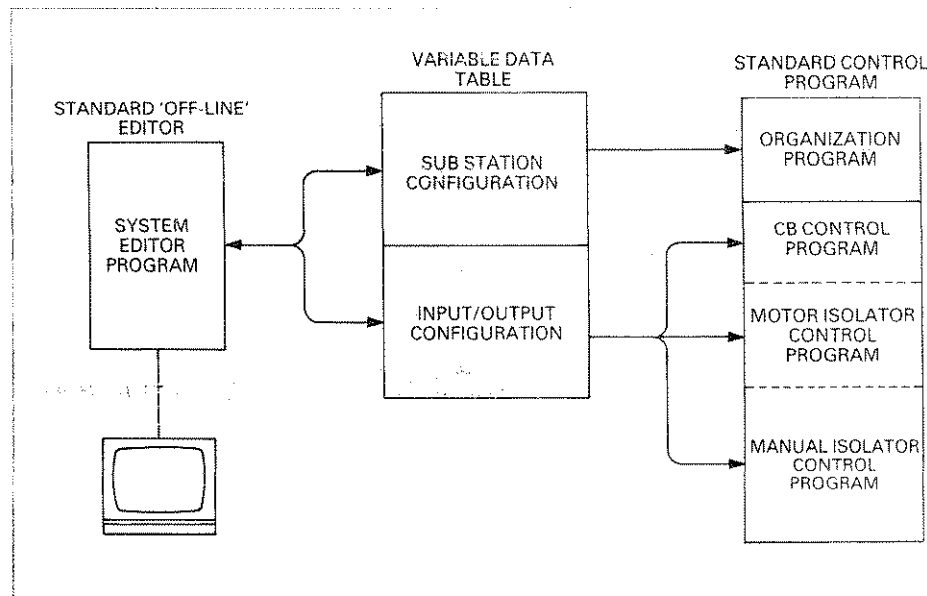


Figure 22.8 Software structure.

There are a number of features which have been found to be desirable in such an event logging system; some of the more common features are:

- Monitoring points at different time resolutions. Protection contacts and circuit breaker auxiliary contacts will need to be logged at a high resolution, such as 1ms, whereas auxiliary contacts from isolators or manually operated equipment can be logged to resolutions of 10ms or 100ms.
- Print-outs at the substation are fully descriptive of the operation, as may be seen from Figure 22.9. However, at a remote monitoring point such as a control centre, a less detailed statement of the event is required, to reduce the burden of information presented to the control engineer at times of crisis.
- The ability to produce, on demand, listings of alarm states or present plant states at the substation to assist in assessing the latest site conditions.
- There are also a number of measures which need to be taken in the software to present the engineer with a more intelligible print out. These include digital filtering to

prevent logging of bouncing contacts and the ability to avoid continuous printing of a 'chattering' contact which would flood the logger with the same messages, also the ability to 'switch-off' signals when maintenance is being carried out in particular areas of a substation.

## 22.14.1

### Operation of event logger software

The microprocessor responds to changes in any of the digital inputs by storing in the RAM the time of the changes, together with point identifications and the senses of the changes (that is, contacts open, contacts closed). For each input change a message is printed identifying the plant area and associated functions.

The processing of information is based on a fixed time period, such as 10ms, which can be subdivided into three separate routines as shown in Figure 22.10.

The inputs from plant and alarm relays are interfaced to the microprocessor via opto-isolators. These inputs are arranged in groups and sampled as words of information as shown in Figure 22.11. The microprocessor samples the present input byte ( $j_n$ ) and compares it with the corresponding byte of data ( $j_{n-1}$ ) from the previous scan.

If no change is detected then the next byte is sampled. However, if a change is detected, the address of the byte, the ( $j_n$ ) and ( $j_{n-1}$ ) bytes are stored in the printing store at the next available location. The ( $j_{n-1}$ ) byte in the past data store is then replaced by the new ( $j_n$ ) byte. The next byte is then sampled and the process continues until all bytes are scanned. When this stage is reached, the input routine gives way to the time keeping routine.

A full 24 hour calendar clock, set by an operator using a teletype keyboard, is maintained including leap year calculations. Actual time is kept in the microcomputer to within 1 second of standard time, with relative time resolution equal to the scan period.

From the data stored in the printing store, a change of any input can be detected. This information is used to

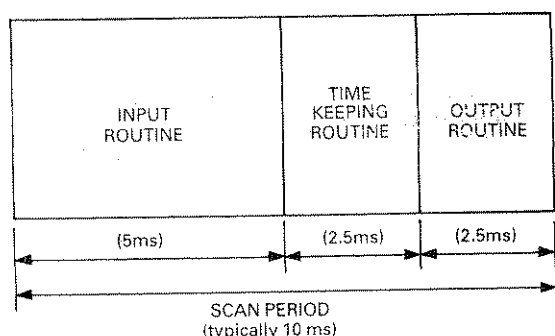


Figure 22.10 Logger processing functions.

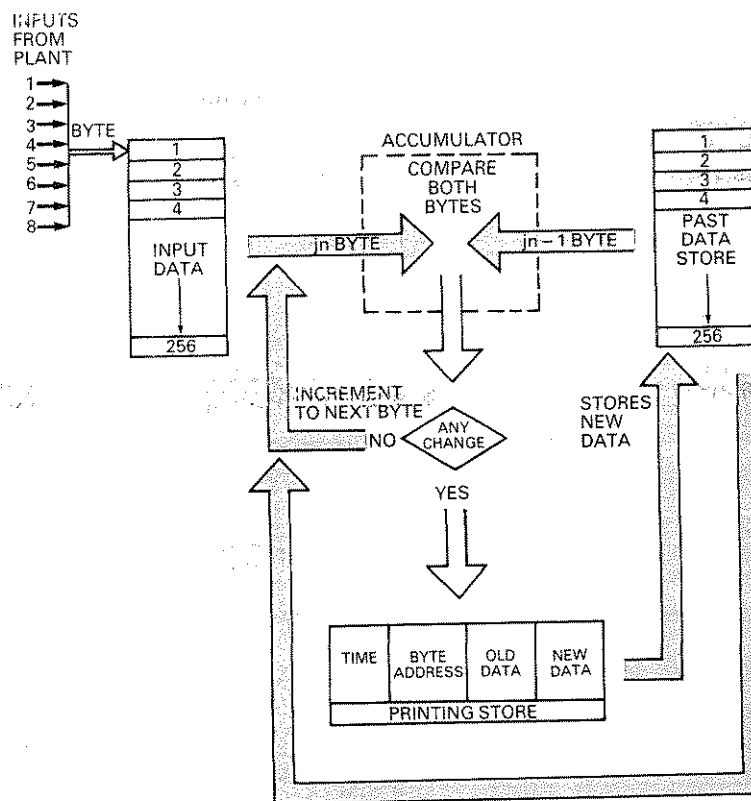


Figure 22.11 Event detection routine.



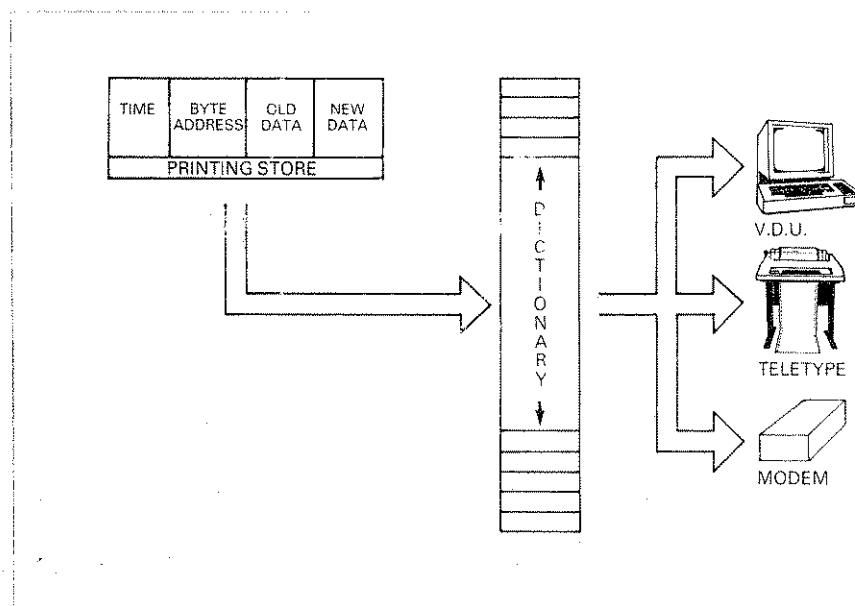


Figure 22.12 Message printing routine.

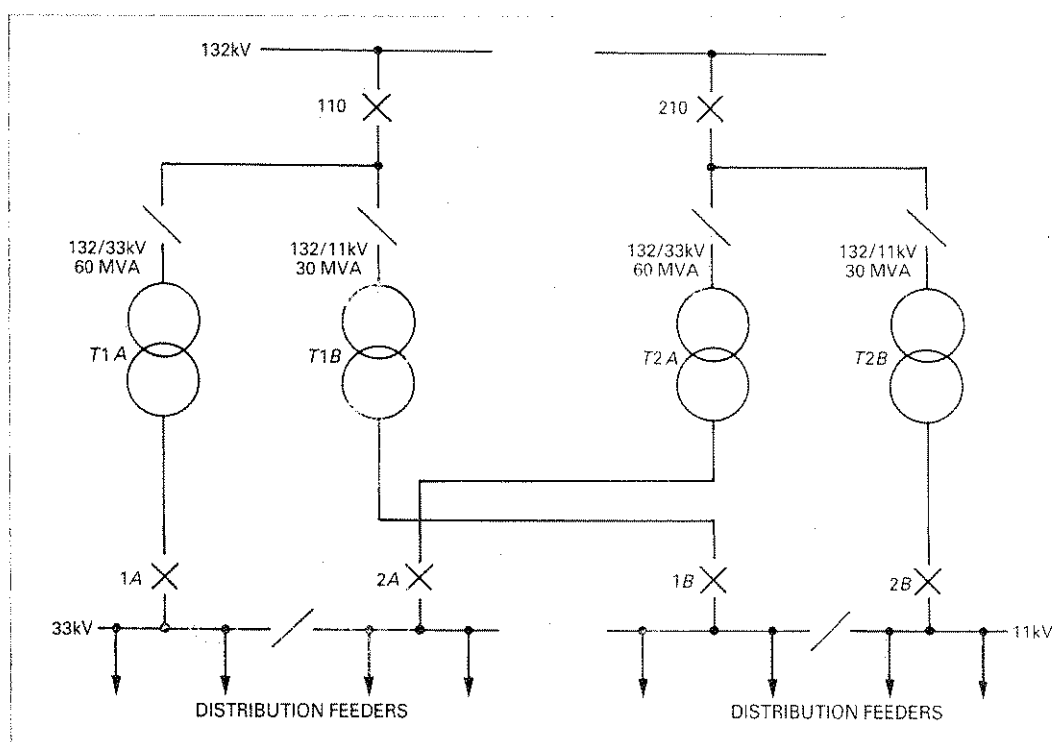


Figure 22.13 Typical four transformer scheme.

construct a message as shown in Figure 22.12 and subsequently print the message on a teletypewriter or VDU.

All messages are stored in EEPROMs to prevent the possibility of accidental loss or corruption in the event of power supply loss. This memory device provides the necessary non-volatile data storage but still allows data to be changed under control of the processor, so allowing on-line text amendment to be carried out.

Some alarm messages and all plant state messages can contain optional phrases depending on the sense of the contact, for example:

Contact closed: AUTO SWITCHING OUT

Contact open: AUTO SWITCHING IN

At an unmanned substation it is possible that in the event of a printer failing after a system disturbance, a number of messages would be lost before the fault is recognized. To prevent this occurring the printer start-up routine uses the

'Printer Available' facility to test the printer before printing each line. If the printer fails, the message 'Local Teletype Fail' is printed out on a remote printer which is connected to the logger via a communications link. Information in RAM relating to changes which cannot be printed will be retained and will output only when the printer becomes operational.

Should the area of RAM allocated to storing changes data be completely used up, because the printer is not operational, the logger will inhibit further storing of data.

## 22.15

22.15.1 Tap-changer control

The microprocessor is also used to control the tap-change mechanism on a distribution transformer, to regulate its output voltage under varying load conditions.

A typical application is the control of tap-change equipment for a group of four transformers, two rated at





change. The test is carried out by adding up all the data in the PROM memory and comparing this with a fixed datum.

**b. RAM check**

The RAM check is performed by taking each RAM location out of service and performing a write/read cycle using test patterns, in order to verify that each bit in every location can be modified under program control.

**c. Microprocessor check**

This performs a logical check on the CPU's registers, using fixed data patterns.

**d. Input/output check**

For this check data from an output port is connected to an input port. The program checks that the data on the input port always matches that on the output port. The state of the latter is changed every cycle of the software.

A failure in any of the above checks results in the control program being suspended and alarm and indications being generated to indicate the type of failure.

The tests described above are performed by the microprocessor on itself, but in addition to these there is an independent timer circuit, commonly known as a 'Watch-dog Timer'. This monitors the cycle time of the software, which should be of a constant period. If this period should vary, the independent timer will lockout the system and generate an alarm.

# Testing and commissioning

- 23.1 Introduction
- 23.2 Factory tests
- 23.3 Production testing
- 23.4 Artificial transmission line
- 23.5 Medium current test plant
- 23.6 Programmable power system simulator
- 23.7 Microprocessor-based portable test set
- 23.8 Vibrator
- 23.9 Climatic simulator
- 23.10 Impulse test equipment
- 23.11 High frequency interference test equipment
- 23.12 Impact test equipment
- 23.13 Initial commissioning tests
- 23.14 Insulation tests
- 23.15 Current transformer tests
- 23.16 Voltage transformer tests
- 23.17 Secondary injection
- 23.18 Primary injection
- 23.19 Tripping and alarm annunciation tests
- 23.20 Periodic maintenance tests
- 23.21 Design features which assist maintenance

## 23.1

The testing of protective schemes has always been a problem, because protective gear is solely concerned with fault conditions, and cannot therefore readily be tested under normal system operating conditions. This situation is aggravated by the increasing complexity of protective schemes and relays.

Protective gear testing may be divided into three stages:

- i. Factory tests.
- ii. Commissioning tests.
- iii. Periodic maintenance tests.

The first two stages prove the performance of the protective equipment during its development, manufacture and in its operational environment. The last stage, properly planned, ensures that this performance is maintained throughout the life of the protective gear.

## 23.2

It is the responsibility of the relay manufacturer to provide adequate and efficient testing of all protective gear before it is accepted and commissioned. Since the prime function of protective relays is to operate correctly under abnormal power conditions, it is essential that their performance be assessed under such conditions. Tests simulating the operational conditions are conducted at the manufacturer's works during the development and certification of the equipment. These tests must be most comprehensive, because modifications to the equipment after installation are both expensive and inconvenient.

The tests performed can be divided into two main groups. The first group includes those tests in which the operating parameters of the relay are simulated. The following testing equipment is used for this purpose:

- i. Production testing equipment.
- ii. Artificial transmission line.
- iii. Medium current test plant.
- iv. Programmable power system simulator.

In the second group of tests, conditions such as temperature, vibration, mechanical shock, electrical impulses and so on, which might affect the correct operation of the relays, are simulated. The testing equipment used for this purpose is as follows:

- i. Vibrator.

- ii. Climatic simulator.
- iii. Impulse test equipment.
- iv. High frequency interference equipment.
- v. Impact test equipment.

In some cases, tests of both groups are conducted simultaneously in order to check the relay performance.

### 23.3

Chapter 7 discusses techniques used to ensure the quality of the components, printed circuit boards and modules used in static relays.

Production testing of protective relays is becoming far more demanding as the accuracy and complexity of the products increase. Electronic power amplifiers are used to supply accurate voltages and currents of high stability to the relay under test. The inclusion of a computer in the test system allows more complex testing to be performed at an economical cost, with the advantage of speed and repeatability of tests from one relay to another.

The block diagram of a manual test bench is illustrated in Figure 23.1. Here all the units which are required in the system are mounted in a special test rack. Dedicated interface adapters are used to ease the connection of the relay to the test system. The application of test sequences and

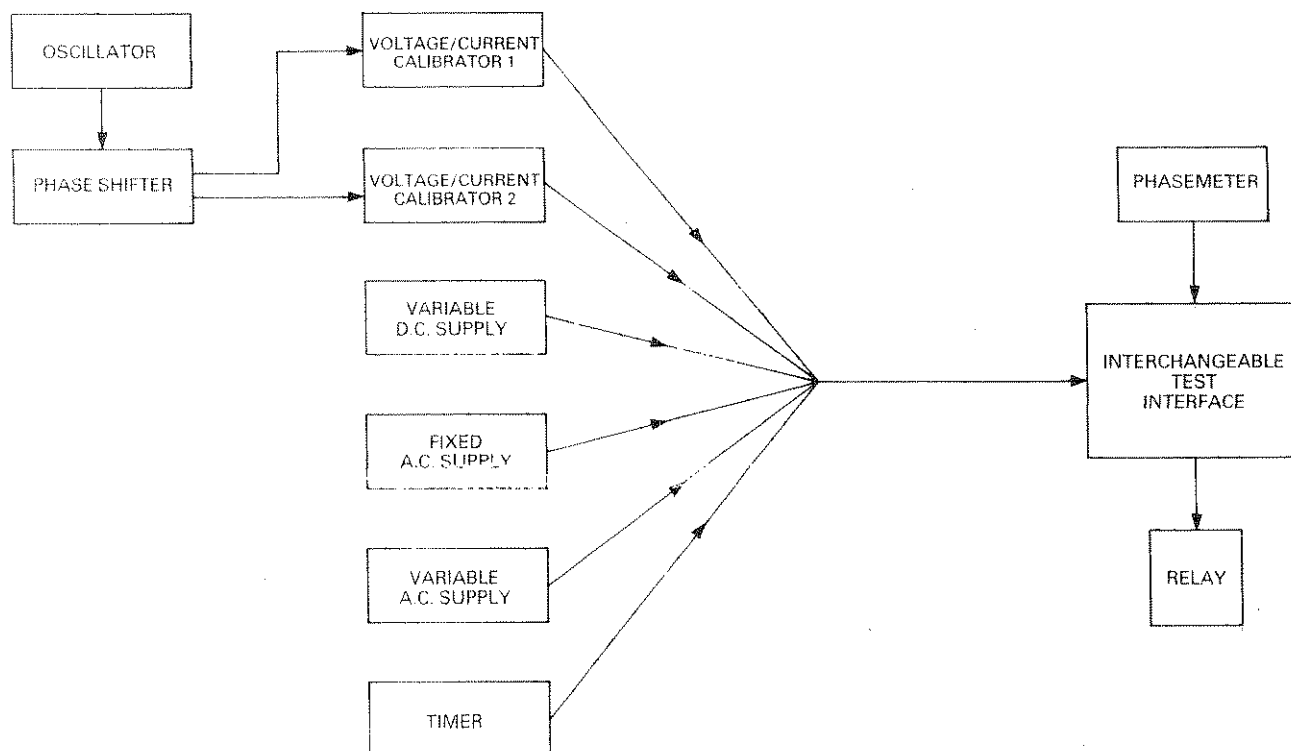


Figure 23.1 Block diagram of single phase test bench



Figure 23.2 Single phase test system (MIDOS relays).

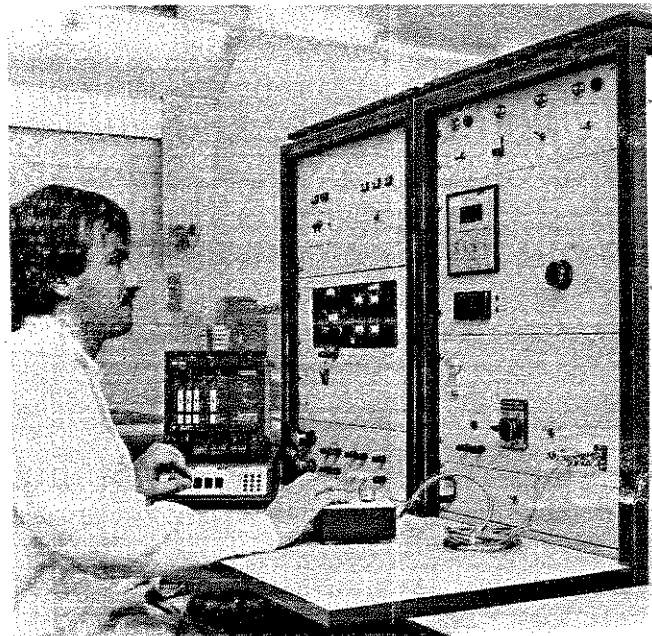


Figure 23.3 Single phase current bench.

the analysis of test results are all manual operations. Two examples of this technique are shown in Figures 23.2 and 23.3.

The block diagram of a computer controlled test bench is illustrated in Figure 23.4. As in the manually operated system, the hardware is mounted in a special rack. Each unit of the test system is connected to the computer via an interface bus. Individual test programs and interfaces are required for each relay type. Control of input waveforms and analogue measurements, the monitoring of output signals and the analysis of test data are performed by the computer. A printout of the test results can also be produced if required. Two examples of this technique are shown in Figures 23.5 and 23.6.

For distance relays the overall characteristics and scheme logic are checked on a production version of the Programmable Power System Simulator described in Section 23.6.

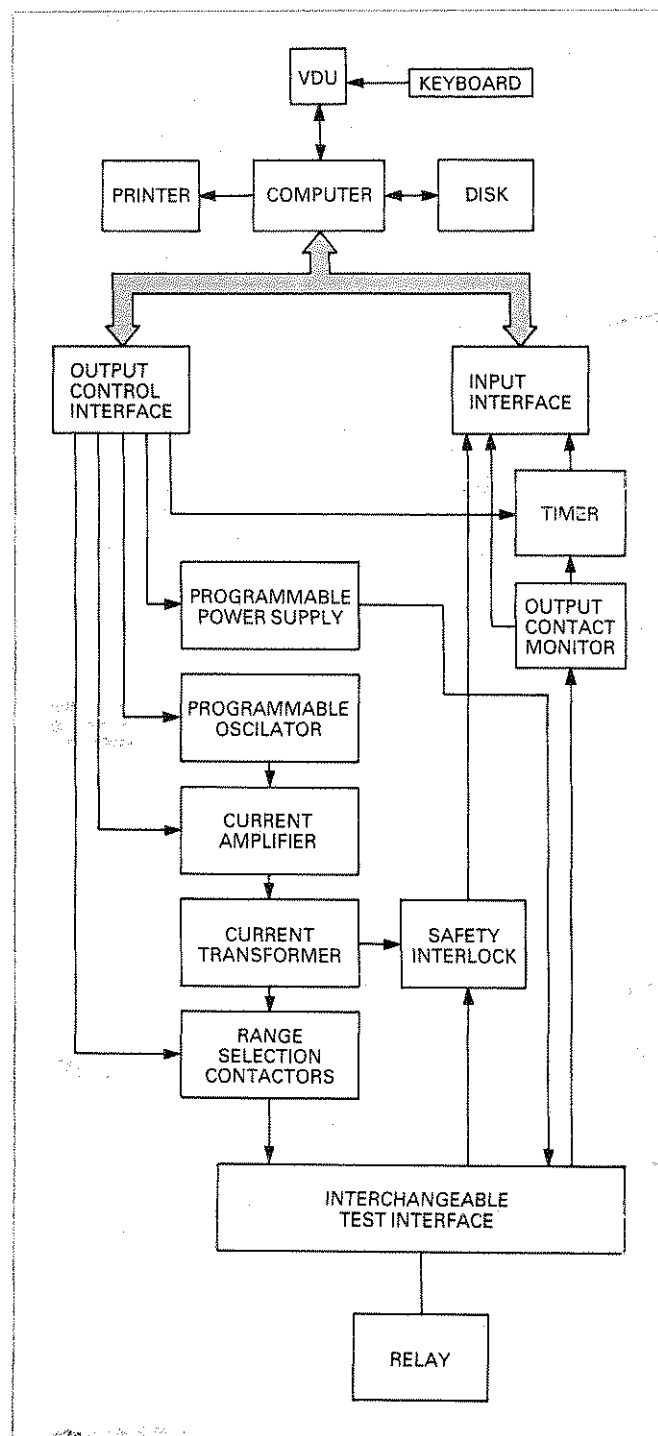


Figure 23.4 System block diagram for computer controlled test bench.



Figure 23.5 Module and relay test system.

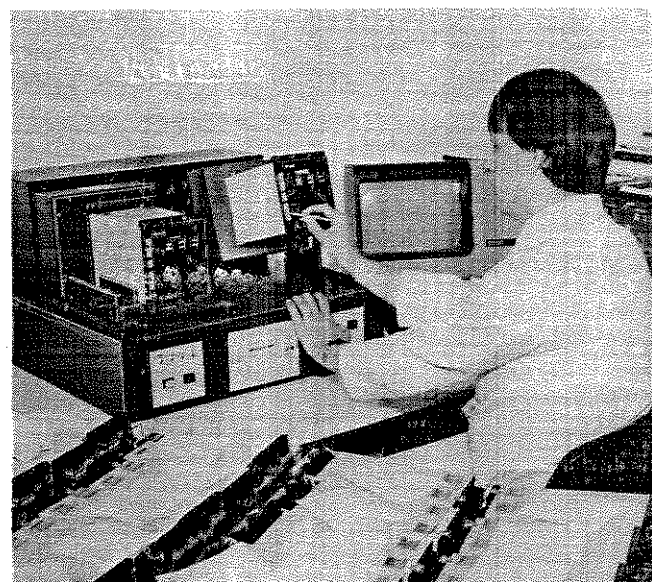


Figure 23.6 MCGG relay test bench.

## 23.4

### ARTIFICIAL TRANSMISSION LINE

The artificial transmission line, shown in Figure 23.7, provides an adjustable current or voltage, or both, at the relaying point, with control of the circuit time constant, duration of fault, point-on-wave at which the fault is applied, and the type of fault. This allows static and dynamic testing over a wide range of simulated steady state and transient power system conditions. It is basically a three-phase circuit, containing impedances, representing source generation levels, transmission line constants, load impedances, fault impedances and earth impedances. All these are independently adjustable, so that the fault MVA linked with the system voltage level, the length of line to fault, system  $Z_0/Z_1$  ratio, source, line and system  $X/R$  ratios and so on, can be completely specified for the particular problem under investigation.

In Figure 23.8 the complete arrangement of one of the artificial transmission lines is shown in schematic form.

The artificial transmission line is supplied from 660 volt three-phase 50 Hz mains, with alternative arrangements for taking the supply from a variable frequency machine.

Maximum fault current is 120 A primary, but, as this passes

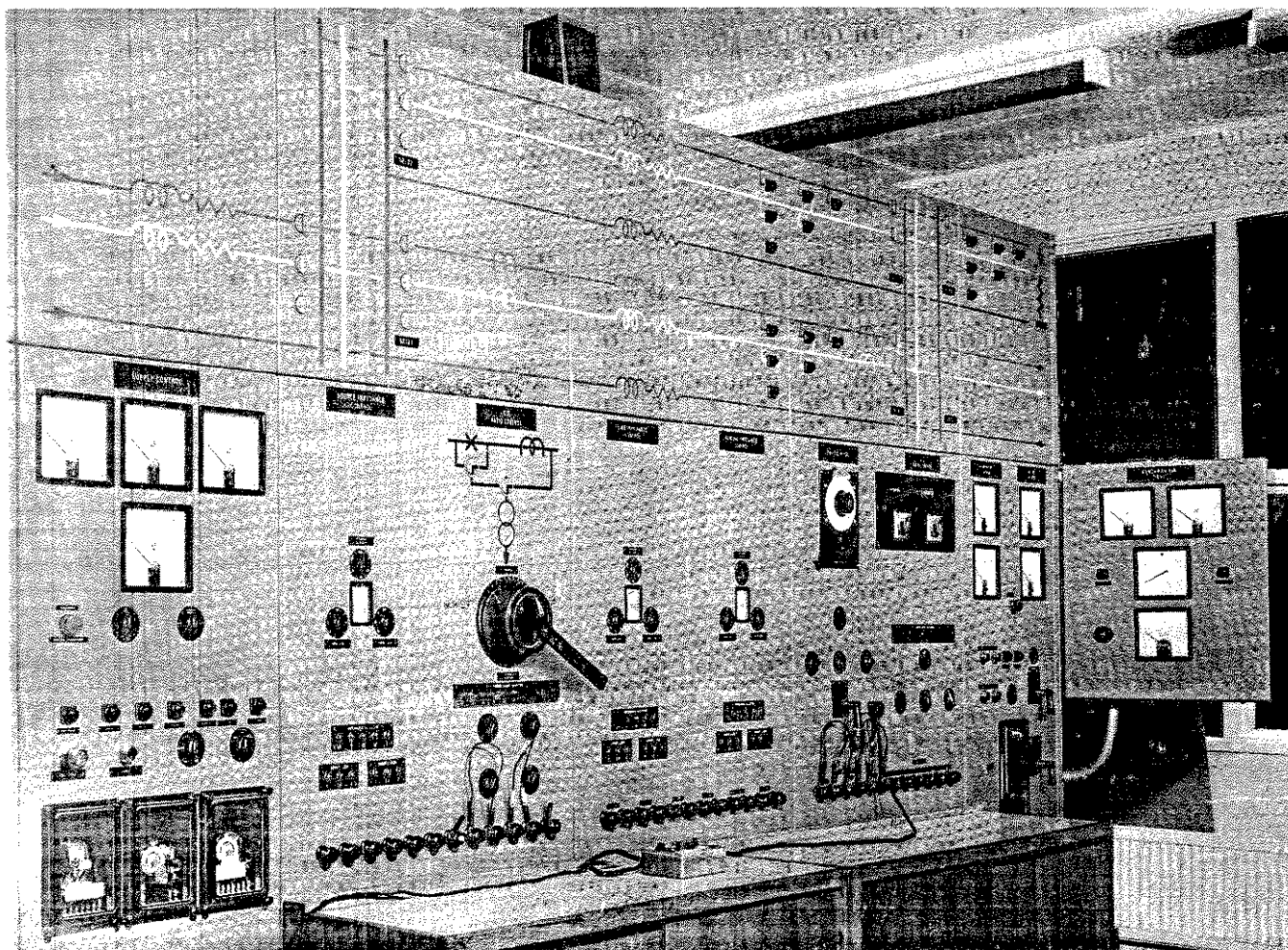


Figure 23.7 Artificial transmission line.

for only a short time, the equipment can have a continuous rating of 30 A.

The source impedance consists of two coils, each having four equal sections. The total series reactance of coil 1 is 48 ohms, that of coil 2 is 96 ohms. By interconnecting the coil sections a total range of 0 to 144 ohms can be obtained in 24 steps. The  $X/R$  ratio of the source is 30 ( $88.1^\circ$ ) and this can be varied by putting resistances in series with each coil section to 20 ( $87.2^\circ$ ) or 10 ( $84.3^\circ$ ).

The line and neutral impedances are similar to the source coils but have values of 2 and 8 ohms. This gives a total range of from 0 to 10 ohms in 24 steps at an  $X/R$  ratio of 10 ( $84.3^\circ$ ). With resistors, the  $X/R$  ratio can be varied to give values of 2.75 ( $70^\circ$ ), 1.73 ( $60^\circ$ ) and 1 ( $45^\circ$ ).

The voltage transformers have ratios of 380/63.5 volts  $\pm 10\%$  and can be connected either to the incoming busbar, the source side of the current transformers, or the line side of the current transformers.

The current transformers have a turns ratio of 50/300. The primary winding (50 turns) is distributed and tapped every 5 turns; the secondary winding is also distributed and tapped at 75 and 150 turns.

An auxiliary secondary with 33 turns is fitted to the source end transformers and is tapped in 1% steps. This can be added to or subtracted from the main secondary to give an adjustment of  $\pm 11\%$ . The total range is from 5.4/1 to 6.6/1 with a 300 turn secondary, and the knee-point voltage is 1000 volts.

All types of fault can be accommodated by suitable switching of contactors and the fault can be applied in one of three positions: internal, external or on the parallel line. The application of the fault is controlled by means of a point-on-wave switch, so giving all degrees of offset. Resistance can be inserted in the fault path to simulate arc resistance.

Relay operation is timed by means of an electronic timing device.

Because of the different functions of the equipment, provision has been made in the design to allow:

- i. Extreme flexibility of test circuits and conditions.
- ii. Rapid setting up of equipment.
- iii. Close control of test conditions and parameters.
- iv. Rapid rate of testing.

The types of protection which may be tested on this equipment include:

- i. High speed pilot wire.
- ii. Generator and transformer differential.
- iii. Instantaneous overcurrent relays.
- iv. Distance impedance.
- v. Distance directional comparison.
- vi. Phase comparison.

Since the power level in the artificial transmission line is substantially less than that in an actual transmission line, while the burden imposed by the relaying schemes is unchanged, the reflected impedance of the relay circuits restricts the range of tests possible on high impedance schemes.

### 23.5

#### LOW GRADIENT TEST PLANT

In protections based on the comparison of the currents at the two sides or ends of the protected part of the system, one of the most important points to be checked is the stability of the protection under external fault conditions. The fault conditions more onerous in this respect are those involving high fault currents with high time constants for the transient component of the fault current.

The correct simulation of the time constant of the transient





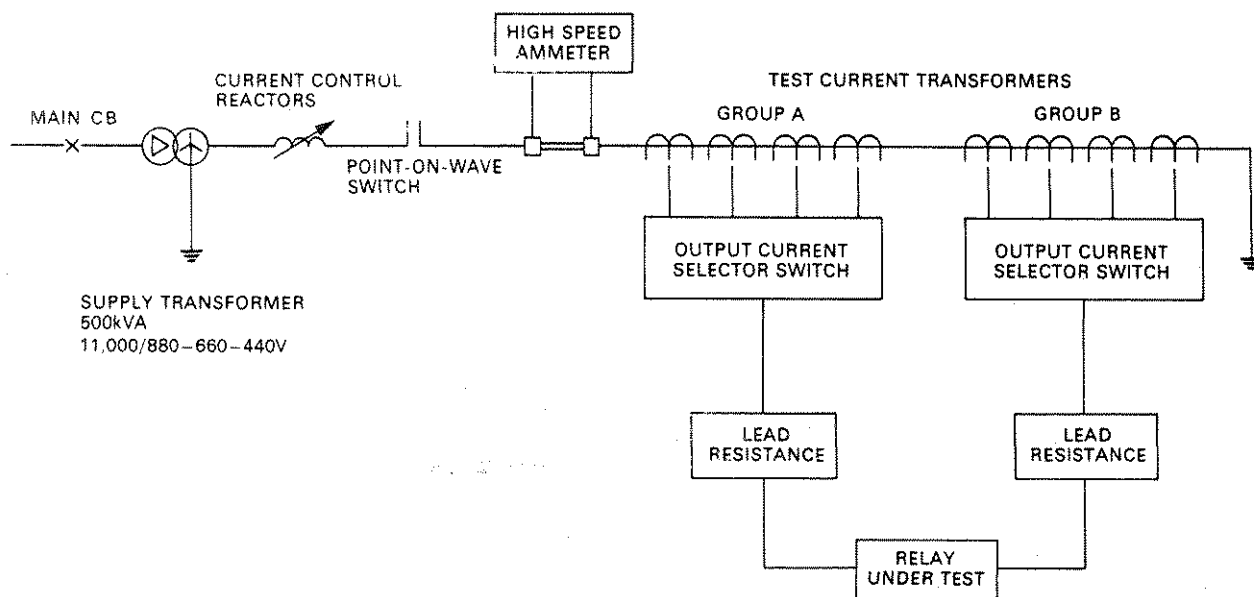


Figure 23.9 Medium current test plant.

component of the fault current is of particular importance, as it determines the degree of transient saturation possible in the current transformers, and thus imposes stringent conditions on the stability and operating speed of the protection. The ability of a test plant to simulate this type of fault depends mainly on the ratio of the power rating of the plant to the relay burden. This ratio is rather low for the artificial transmission line, since, because of the relative complexity of the power system being simulated, the cost would otherwise have been prohibitive.

For the purpose of testing balanced-type protections, therefore, a less complex test plant with a higher power rating is provided. A single line diagram of the test plant is shown in Figure 23.9. The value of the reactors shown in this figure can be altered independently to give any combination of fault currents and  $X/R$  ratios. The maximum primary current that can be obtained in this way is 510 A per phase. This current is fed to the relays to be tested via current transformers with ratios of 10/1 A and 20/1 A. The effective knee-point voltage of the current transformers can be varied between 160 volts and 2000 volts by connecting one or more current transformers in series.

The simulated fault current can be adjusted by changing the value of the reactors and also by changing the supply voltage. Three different voltages, 880 V, 660 V and 440 V, are available for this purpose in the 500 kVA supply transformer. A three-phase voltage supply is available for testing relays operating with both current and voltage.

As in the case of the artificial transmission line, the fault can be applied at any point on the voltage wave in order to obtain different degrees of asymmetry in the fault current.

Among other facilities available in this test plant, there are resistor banks for simulation of the lead burden in the secondary side of the current transformers, a high speed ammeter to enable an accurate reading of the current to be taken when the duration of the test is short, a three-phase resistor bank for secondary relay injection with a maximum current rating of 150 A at 510 V, and a 60 kVA power transformer for magnetizing inrush purposes.

The nominal  $X/R$  ratio of the reactors that limit the fault current is 30. However, the value is reduced in practice by the resistance of the connections, the windings of the

current transformers and the relays, and also according to the fault current level being simulated. The  $X/R$  ratios obtained with this test plant have been satisfactory until recently. However, the great increase in the power system fault levels and time constants experienced in recent years has created conditions which cannot be economically simulated in this type of test plant.

In order to test protective equipment under these extreme conditions a separate test plant based on a new principle has been built. A single line diagram of the test circuit is shown in Figure 23.10. The operating principle consists basically of generating the transient component of the fault current via capacitor bank  $C$  and resistor bank  $R2$ , and the steady state component of the fault current via resistor bank  $R1$ . These two components of the fault current are then superimposed at the terminals of the current transformers. With this method, the simulated  $X/R$  ratio of the test plant is practically unaffected by the relay burden and the resistance of the leads. The secondary fault current can be adjusted between zero and 60 A in steps of 1 A. The simulated  $X/R$  ratios at maximum fault current can be adjusted between 5 and 40 in small discrete steps. At lower fault currents the maximum  $X/R$  ratio increases proportionally, the product of the nominal secondary fault current and maximum  $X/R$  ratio being constant at 2400.

Burdens up to 30 VA (at rated current) can be connected to the test plant depending on the magnitude of the fault current and the maximum errors that can be allowed.

A point-on-wave control unit is used in conjunction with this test plant to control the simultaneous switching of the supplies for the steady state and transient components of the fault current. The point-on-wave can be adjusted between zero and  $360^\circ$  in steps of  $10^\circ$ . The switching of the main current is done statically, by means of triacs for the steady state component and by thyristors for the transient uni-directional component. The selection of all the variable parameters (fault current,  $X/R$  ratio, type of fault and point-on-wave) is done from the control board illustrated in Figure 23.11 by means of push-buttons. This form of control permits rapid testing.

The current transformers, relay cubicles, and other facilities available for the standard medium current test plant previously described are also used in this test plant.



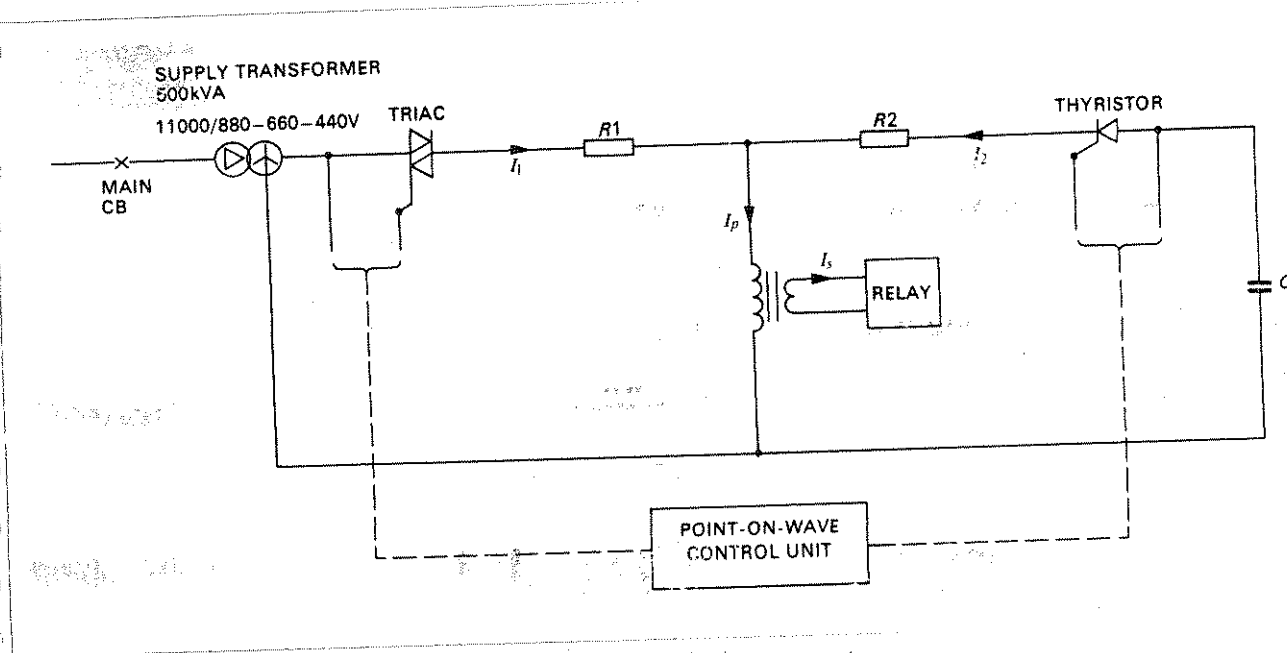


Figure 23.10 Basic circuit to achieve effect of high  $X/R$  ratio in CT primary current.

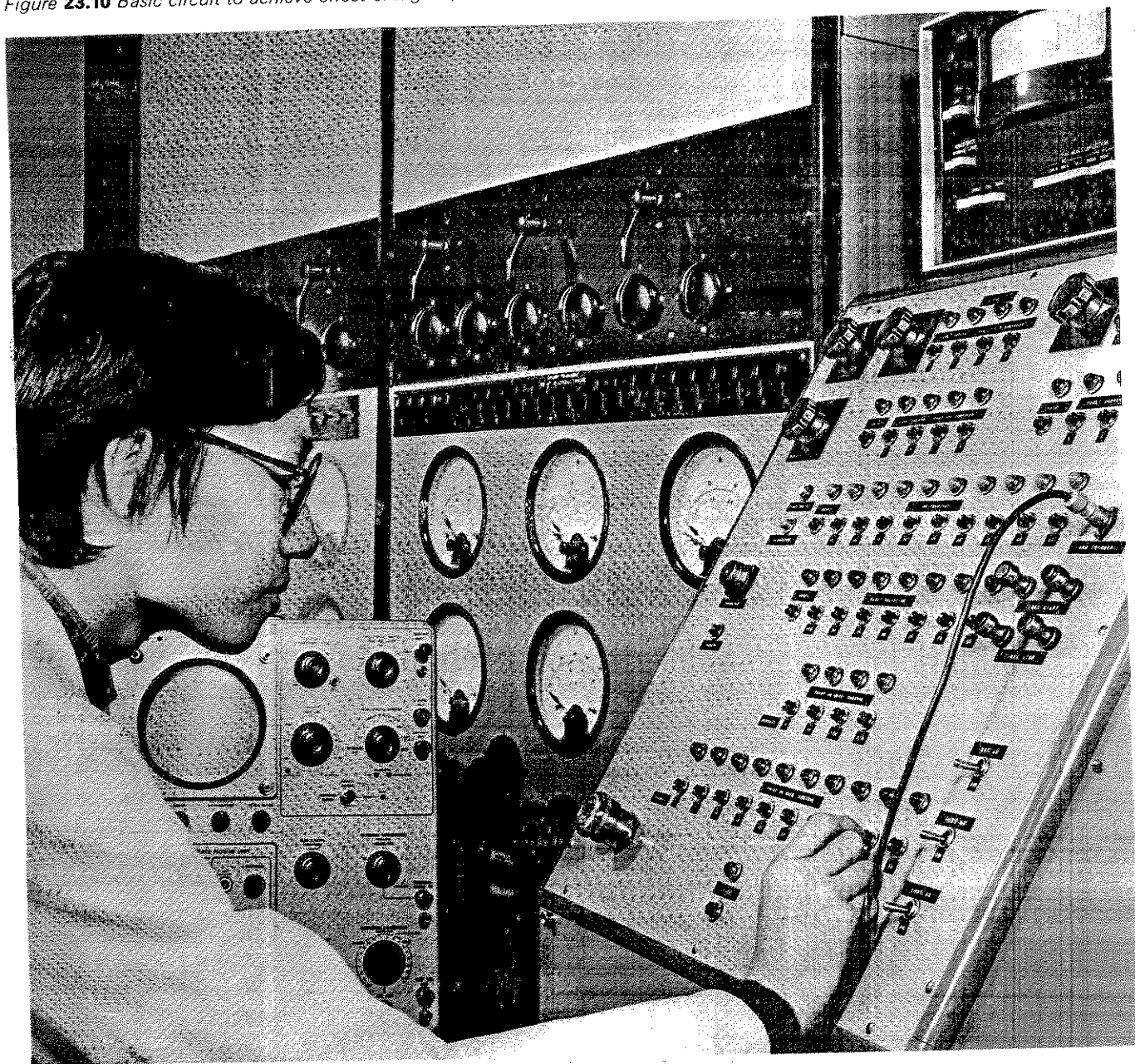


Figure 23.11 Push-button control panel for medium current test plant.

There are two possible methods of proving the satisfactory performance of protection schemes to meet given applications; the first method is by actually applying faults on the power system and the second is to carry out comprehensive testing on a power system simulator.

The former method obviously has severe limitations as it is practical to apply only a very limited number of faults and it is also difficult to apply faults at various points of wave and under varying system conditions likely to be experienced by the protection when in service.

Because of this it has been considered necessary, in the past, to have a proving period for new protection equipments under service conditions. But because faults may occur on the power system at very infrequent intervals, it can take a number of years before any possible shortcomings are discovered, during which time a large number of equipments could be installed on the power system.

The most important part of any development and manufacturing programme is the testing of the complete relay scheme as this is the user's best guarantee that the scheme will perform reliably when it is installed on the power system.

In recognition of this a new generation power system simulator has been developed which is capable of providing a far more accurate simulation of power system conditions than has been possible in the past. The simulator enables relays to be tested under a wide range of system conditions representing the equivalent of many years of site experience.

### 23.6.1

#### Existing approaches

For many years relays have been tested on analogue models of power systems such as the Artificial Transmission Line (ATL), described in Section 23.4, which uses

lumped inductance and resistance to represent the source, line, load and neutral impedances plus fault resistance.

The PPSS is particularly suitable for type-testing modern high speed protection because it is not subject to the several inherent limitations of its predecessors:

- The power system model is capable of reproducing high frequency transients such as travelling waves.
- Tests involving very long time constants can be carried out.
- It is not affected by the harmonic content, noise and frequency variations in the a.c. supply.
- It is capable of representing the variation in the current associated with generator faults and power swings.

### 23.6.2

#### Equipment description

The computer-based power system simulator used at GEC ALSTHOM Measurements has been specifically designed for the testing of high speed relays (having operating times of less than 10 ms) under transient conditions similar to those experienced in practice, thereby ensuring reliable operation under service conditions. It comprises a mathematical model of the power system (the simulation) and a means of using the data from that model to test relays.

The equipment, shown in block schematic form in Figure 23.12, is based around a general purpose minicomputer which calculates and stores the digital data representing the system voltages and currents. The minicomputer controls conversion of the digital data into analogue signals, and it monitors and controls the relays being tested. The analogue signals are processed to removed the 'steps' produced by digital to analogue conversion and amplified to the levels associated with the secondary circuits of power system transducers.

Analogue models of the system transducer characteristics can be interposed between the signal processors and the power amplifiers.

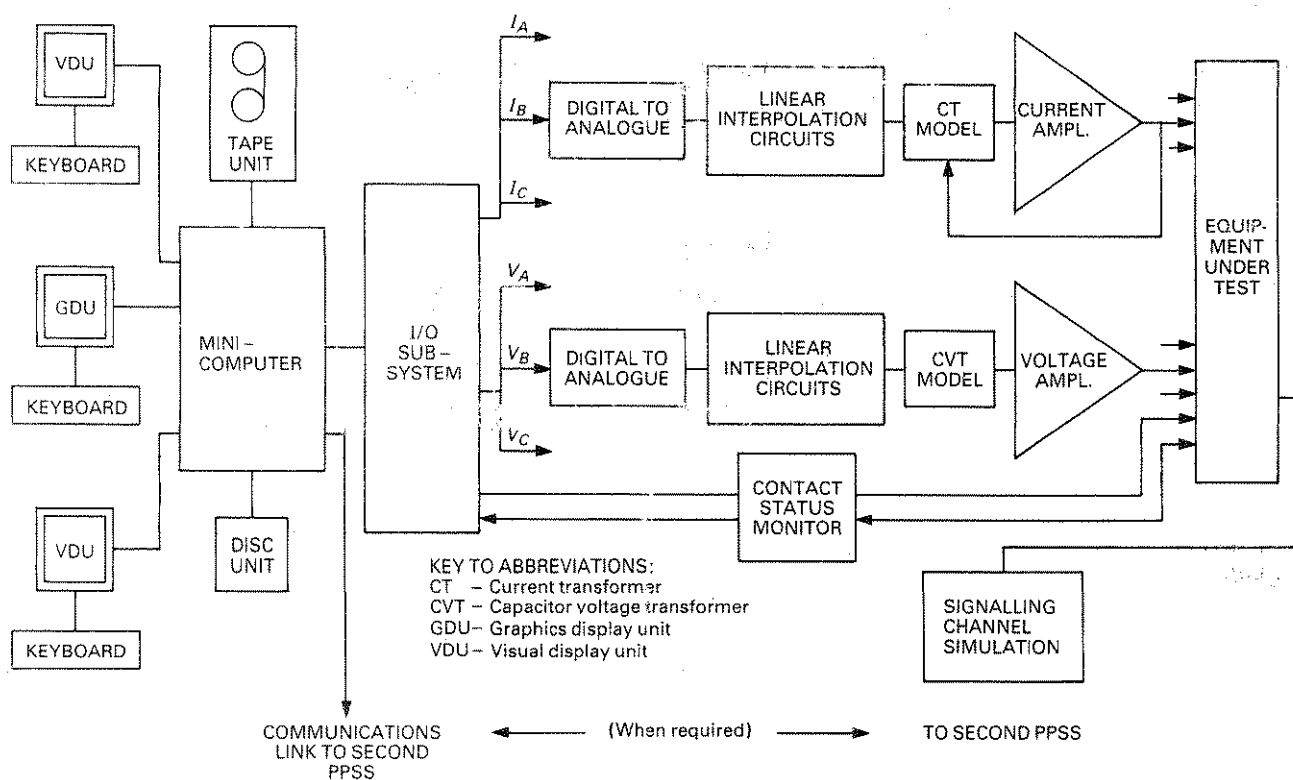


Figure 23.12 Block diagram of programmable power system simulator.

For investigating relay performance under system transient conditions very accurate power system simulations are used. The simulation program is run on a mainframe computer and magnetic tapes are generated to provide the data to test the protection equipment on the power system simulator.

### 23.6.3 Simulation programs

Two very accurate simulation programs are used, the one based on time domain and the second on frequency domain techniques. In both programs single and double circuit transmission lines are represented by fully distributed parameter models. The line parameters are calculated from the physical construction of the line, taking into account the effect of conductor geometry, conductor internal impedance and the earth return path and including the frequency dependence of the line parameters in the frequency domain program, where appropriate.

The frequency dependent variable effects are calculated using Fast Fourier Transforms and the results are converted to the time domain.

The line can be symmetrical, asymmetrical, transposed or non-transposed.

The fault can be applied at any one point in the system and can be any combination of phase to phase or phase to

earth, resistive, or non-linear phase to earth arcing faults. For series compensated lines, flashover across a series capacitor following a short circuit fault can be simulated.

Conventional current transformers and capacitor voltage transformers are also simulated.

The frequency domain model is not suitable for developing faults and switching sequences, therefore the widely used Electromagnetic Transient Program (EMTP), working in the time domain, is employed in such cases. However, the EMTP is less suitable for representing the frequency dependent parameters of a line.

In addition to these two programs, a simulation program based on lumped resistance and inductance parameters is used. This simulation, which is executed on the mini-computer, is used to represent systems with long time constants and slow system changes due, for example, to power swings.

Figure 23.13(a) shows a section of a particular power system modelled. The waveforms of Figures 23.13(b) and 23.13(c) show the three phase voltages and currents at the relay location R for the fault condition indicated in Figure 23.13(a).

### 23.6.4 Applications

The PPSS is used for checking the accuracy of calibration and performing type tests on a wide range of power system

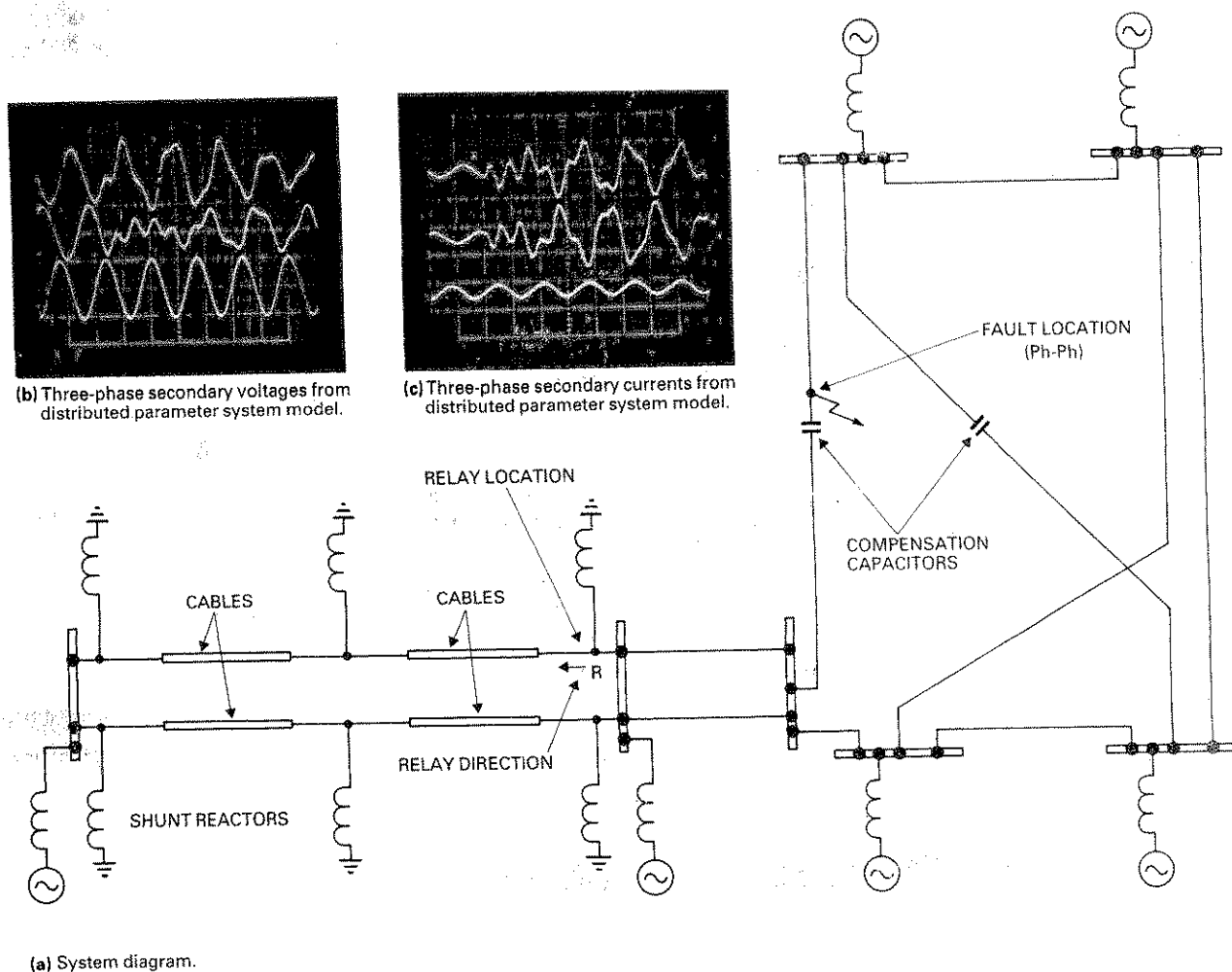


Figure 23.13 Example of application study.

protection relays during their development. It has the following advantages over existing test methods:

- 'State of the art' power system modelling data can be used to test relays.
- Freedom from frequency variations and noise or harmonic content of the a.c. supply.
- The relay under test does not burden the power system simulation.
- All tests are accurately repeatable.
- Wide bandwidth signals can be produced.
- A wide range of frequencies can be reproduced.
- Selected harmonics may be superimposed on the power frequency.
- The use of direct coupled current amplifiers allows time constants of any length.
- Capable of simulating slow system changes.
- Reproduces fault currents whose peak amplitude varies with time.
- Transducer models can be included.
- Automatic testing removes the likelihood of measurement and setting errors.
- Two such equipments can be linked together to simulate a system model with two relaying points.

A PPSS is also used for the production testing of relays, in which most of the advantages listed above apply. As the

tests and measurements are made automatically, the quality of testing is also greatly enhanced.

In general, the PPSS can be used to test any single or three phase, current and/or voltage operated device using any mathematical model of a power system which can be implemented on a computer, within the constraints imposed by the sample rate and test duration.

### 23.7

#### MICROPROCESSOR-BASED PORTABLE TEST SETS

Computerized equipments are also available for automatic 'on-site' testing of protective relays.\* The testing carried out in substations, for commissioning or maintenance, is normally the minimum necessary to ensure that the protective relays are capable of operating satisfactorily. But the need to minimize outage time, and the complexity of some modern protection equipment, particularly distance protection, has provided the incentive for enabling more rapid and comprehensive site testing by microprocessor-based portable test sets.

These sets typically comprise a controller unit, power amplifiers for test current and voltage, and equipment such as a VDU, digital instruments and printers/plotters to show the test results. This hardware is arranged in various units to facilitate portability and flexible testing combinations.

Different test programs and interfaces are generally

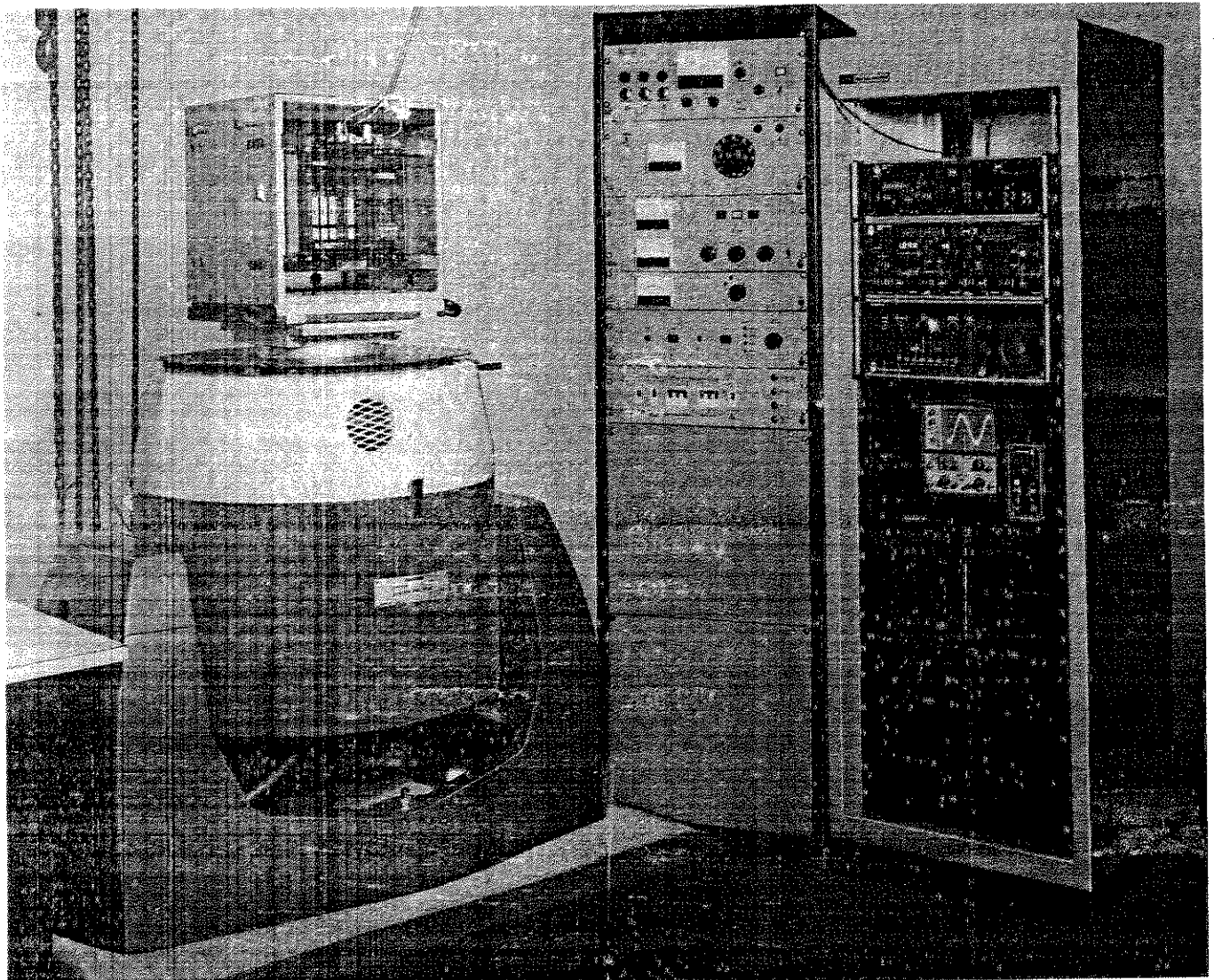


Figure 23.14 Vibration equipment.

\*Computerized 'In-Situ' Testing of Feeder Protections. A. C. Webb. IEE PROC. Volume 130, Pt.C, Number 1, January 1983



required for each specific type of relay. The test programs may be interchanged by cassette tapes, or by introducing the respective data for each relay by keyboard control. The interfaces must be tailored to the individual relay under test, to enable the mini-computer to monitor most effectively the responses of the relay to the test conditions imposed on it.

Relay minimum operating levels for input quantities such as current or voltage are checked by applying the quantity in progressive steps of a size selected to give an optimum compromise between accuracy and speed of testing. For example, a test program for a distance relay, including the checking of distance reach for each measuring element, zone timing intervals and polar diagrams of the operation zones, can be completed in less than half an hour. It must be appreciated, though, that time saving is more apparent from the aspect of routine periodic testing, rather than in respect of full commissioning procedures for which the limitations of automatic test equipment may effect their advantages over a fully manually controlled set.

Nevertheless, it is now accepted that the designs of any modern, complex, static protection equipment should provide access facilities for automatic testing from the outset, and conversely, the major automatic testing equip-

ment manufacturers endeavour to make suitable interfacing equipment available to ensure compatibility.

### 23.8

#### Vibration

The performance of relays should be checked with the maximum levels of vibration which may be present in the relay panel. The British Standard BS142 lists the vibration tests that should be carried out on protective relays. The testing equipment used for this purpose consists of an oscillator, an amplifier and a vibrator in combination. The vibration equipment, illustrated in Figure 23.14, has a frequency range of zero to 5 kHz and can produce accelerations of up to 100 g. Vibration can be applied to the equipment in any plane and for any period of time.

The capability of the testing equipment well exceeds the maximum limits recommended for the test in the British Standard.

It is GEC ALSTHOM Measurements' experience that relays which have passed the BS142 Mechanical Stability Tests for vibration and impact are well able to withstand the seismic tests applied, in the manner currently preferred, to the complete switchgear units and relay panels on which the relays are mounted.

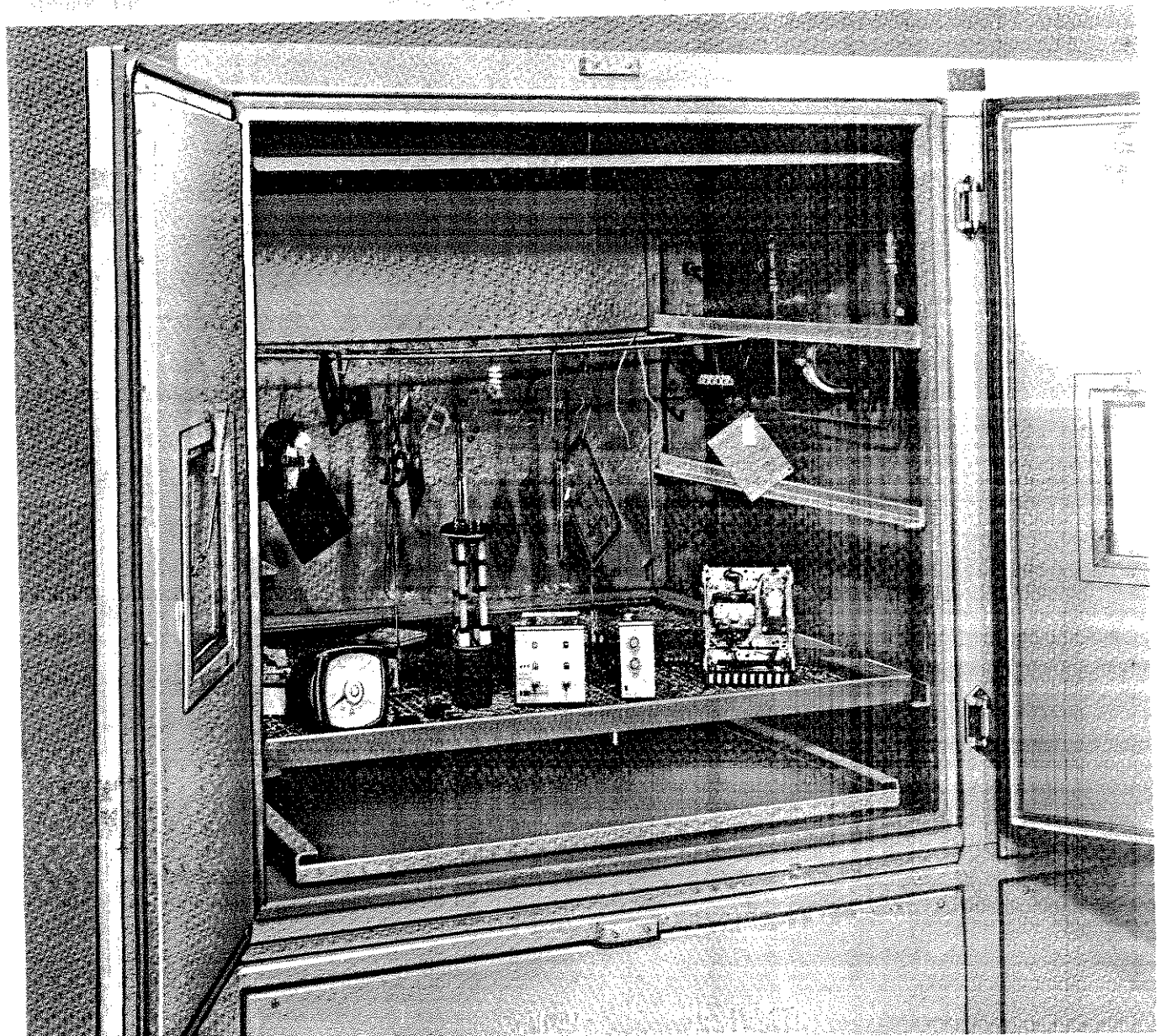


Figure 23.15 Climatic simulator cabinet.

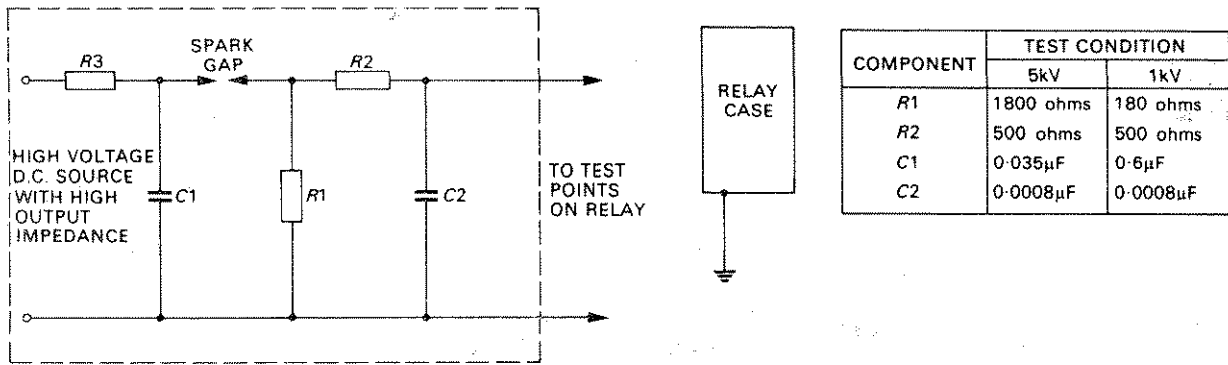


Figure 23.16 Impulse generator circuit.

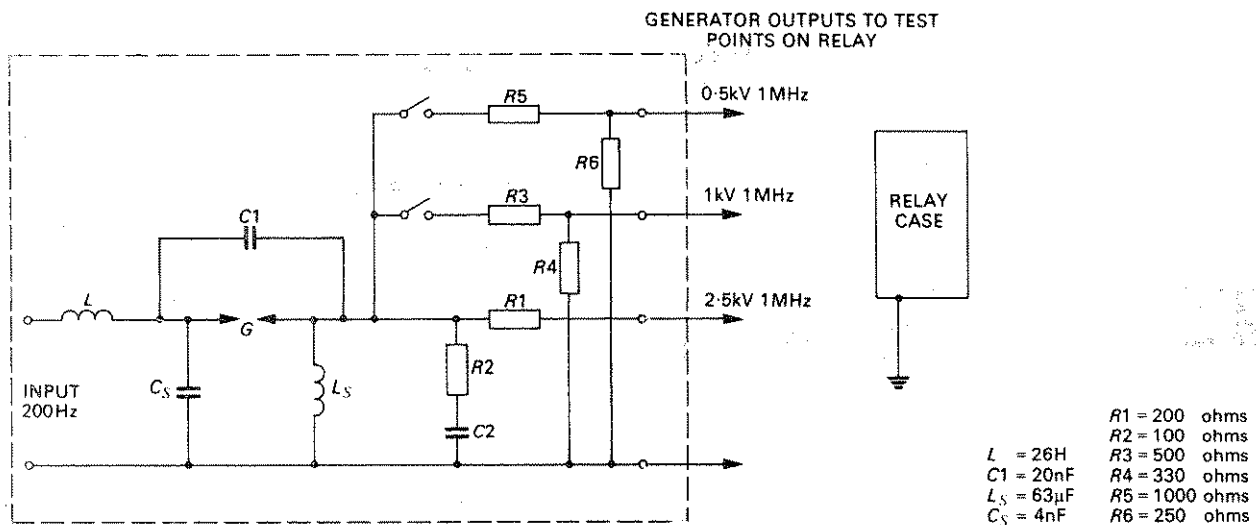


Figure 23.17 Circuit for generating high frequency damped oscillatory waves.

### 23.9

Temperature and humidity are two other factors that can have a great influence on the performance of relays if these are not properly designed and constructed. With the climatic simulator shown in Figure 23.15, environments with temperatures from  $-10^{\circ}C$  to  $+100^{\circ}C$  at any practical humidity levels can be simulated for any period of time.

### 23.10

Protective relays, particularly static relays, may be damaged if transient waves with steep fronts are present in the incoming conductors. An exponential wave with a rise time of 1.2 microseconds and a fall time of 50 microseconds is recommended by the International Electrotechnical Commission (I.E.C. Publication 60) for the purpose of these tests. The peak value of the voltage wave applied to the equipment varies between 1kV and 5kV depending on the nature and location of the external wiring which is to be connected to the relay.

The testing equipment used to produce this voltage wave is shown in Figure 23.16.

### 23.11

The operation of HV switchgear near a protective relay or

the leads connected to it may give rise to high frequency transients in the relay circuits. The operation of the protective relay should not be affected by the presence of these transients. The testing equipment used to check the performance of the relay under these conditions produces high frequency transients which have been assessed by the International Electrotechnical Commission as being representative of practical system conditions. These transients consist of damped oscillatory voltage waves of 1 MHz with the envelope of the wave decaying to 50% of the peak value in 3 to 6 cycles. The oscillatory wave is repeated at a rate of 400 per second for two seconds. As in the case of the impulse tests, the peak value of the test voltage depends on the nature of the external wiring to be connected to the relay and may vary between 1kV and 2.5kV. The equipment used to generate the transients is illustrated in Figure 23.17.

### 23.12

#### IMPACT TEST EQUIPMENT

Before the introduction of impact testing as standard, protective relays occasionally maloperated as a result of being accidentally knocked, causing, in a few instances, severe disruption of the power system. Sensitive electromagnetic relays are particularly prone to maloperation unless special precautions are taken in their construction. Nevertheless, all relays are subjected to tests simulating these conditions. The equipment used for this purpose is shown in Figure 23.18; it consists of a hammer hung from the top of the panel in which the relay to be tested is



Figure 23.18 Impact test panel.

mounted. A number of blows is applied to the panel with the hammer. The relay should be stable during the test and no parts of the relay should be damaged or displaced when the test has been completed.

### 23.13

#### INITIAL COMMISSIONING TESTS

It is usually the responsibility of the manufacturer to commission plant, but this depends on the terms of the contract between the customer and manufacturer and also on the complexity of the plant being commissioned.

The commissioning tests normally carried out are summarized below:

- i. Check the wiring diagrams used by the erectors. Circuit diagrams showing all the reference numbers of the interconnecting wiring greatly assist in this work.
- ii. Make a general inspection of the equipment, checking all connections, wires on relays terminals, labels on terminal boards and so on.
- iii. Measure the insulation resistance of all circuits.
- iv. Test main current transformers for ratio and polarity, and check points on the magnetization curve.
- v. Test main voltage transformers for ratio, polarity and phasing.
- vi. Inspect and test the relays by secondary injection.
- vii. Check the equipment by primary injection to prove stability for external faults and to determine the effective current setting for internal faults.
- viii. Check the tripping and alarm circuits for the equipment.

### 23.14

All the deliberate earth connections on the wiring to be tested should first be removed, for example earthing links on current transformers, voltage transformers, and d.c. supplies.

Some insulation testers generate impulses with peak voltages exceeding 5 kV: in these instances any transistorized equipment should be removed from its case while the external wiring insulation is checked.

The insulation resistance should be measured to earth and between electrically separate circuits.

The readings should then be recorded and compared with subsequent routine tests to check for any deterioration of the insulation.

The insulation resistance measured depends on the amount of wiring involved, its grade, and the site humidity. Generally, if the test is restricted to one cubicle, a reading of several hundred megohms should be obtained. If long lengths of site wiring are involved the reading could be only a few megohms.

### 23.15

#### 23.15.1

#### Polarity check

Each current transformer should be individually tested to verify that the primary and secondary polarity markings are correct; see Figure 23.19. The ammeter connected to the secondary of the current transformer should be a robust moving coil, permanent magnet, centre zero type. A low voltage battery is used, via a single-pole push-button switch, to energize the primary winding. On closing the push-button the d.c. ammeter, A, should give a positive flick and on opening, a negative flick.

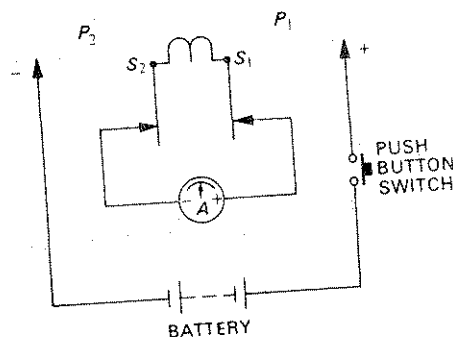


Figure 23.19 Current transformer polarity check.

### 23.15.2

#### Ratio check

This check is usually carried out during the primary injection tests described later. Current is passed through the primary conductors and measured on the test set ammeter, A1 in Figure 23.20. The secondary current is measured on the ammeter A2, and the ratio of the value on A1 to that on A2 should approximate to the ratio marked on the current transformer nameplate.

### 23.15.3

#### Magnetization curve

Several points should be checked on each current transformer magnetization curve. This can be done by energizing

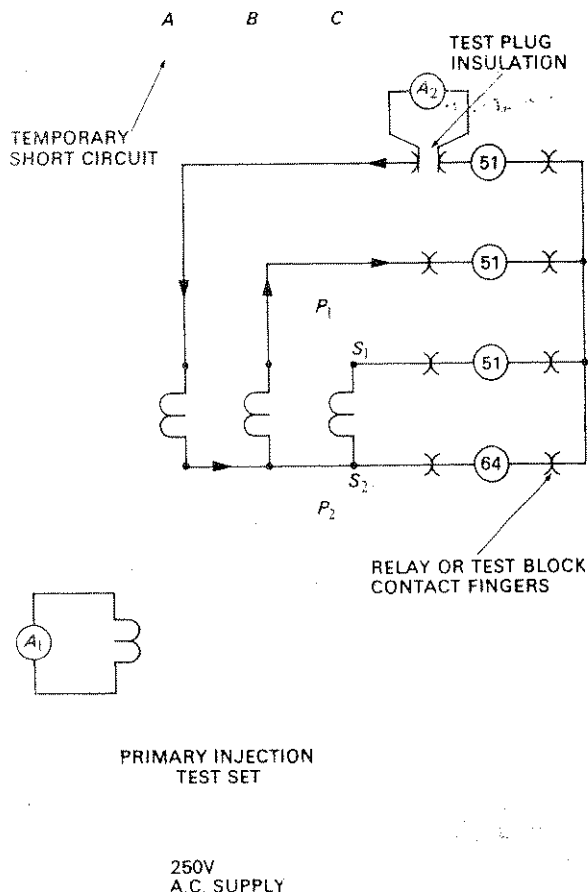


Figure 23.20 Current transformer ratio check.

the secondary winding from the local mains supply through a variable auto-transformer while the primary circuit remains open; see Figure 23.21. The magnetizing current is measured on the ammeter  $A$ , and the secondary voltage on the voltmeter  $V$ . The applied voltage should be slowly raised until the magnetizing current is seen to rise very rapidly for a small increase in voltage. This indicates the approximate knee-point or saturation flux level of the current transformer. The magnetizing current should then

be recorded for several levels of secondary voltage as the voltage is reduced to zero.

It is recommended that an auto-transformer of at least 8 amperes rating be used when the current transformers being tested are rated at 5 amperes secondary. As the magnetizing current will not be sinusoidal, an ammeter of the moving iron or dynamometer type should be used. Generally, the knee-point level of the current transformer should be reached when the secondary voltage is raised until the magnetizing current is equal to the rated secondary current.

It is often found that current transformers with secondary ratings of 1 ampere or less have a knee-point voltage higher than the local mains supply. In these cases a step-up interposing transformer must be used to obtain the necessary voltage to check the magnetization curve.

## 23.16

### VOLTAGE TRANSFORMER TESTS

#### 23.16.1

##### Polarity check

The voltage transformer polarity can be checked with the test described for the main current transformers. Care must be taken to connect the battery supply to the primary winding, with the polarity ammeter connected to the secondary winding. If the voltage transformer is of the capacitor type, then the polarity of the transformer at the bottom of the capacitor stack should be checked.

#### 23.16.2

##### Ratio check

This check can be carried out when the main circuit is first made alive. The voltage transformer secondary voltage is compared with the secondary voltage of a voltage transformer already connected to the same primary bars.

#### 23.16.3

##### Phasing check

The secondary connections for a three phase voltage transformer or a bank of three single-voltage transformers must be carefully checked for phasing. With the main circuit alive, the secondary voltages between the phases and neutral must be measured for correct magnitudes. The phase rotation should then be checked with a phase rotation meter connected across the three phases, as shown in

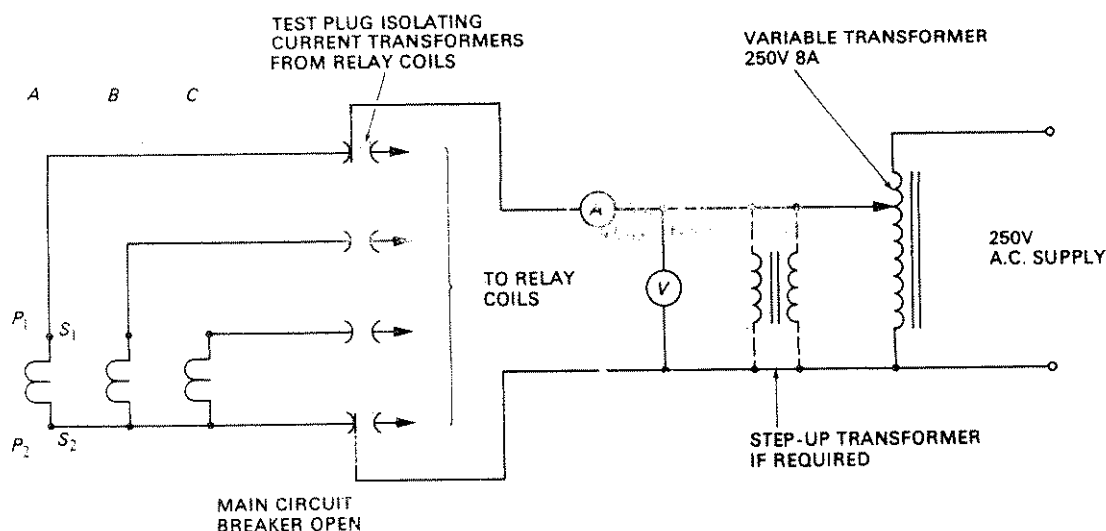


Figure 23.21 Testing current transformer magnetizing curve.



Figure 23.22. Provided an existing proven VT is available on the same primary system, and that secondary earthing is employed, all that is now necessary to prove correct phasing is a voltage check between, say, both 'A' phase secondary outputs. There should be nominally little or no voltage if the phasing is correct.

Correct phasing should be further substantiated when carrying out 'on load' tests on any phase-angle sensitive relays, at the relay terminals. Load current in a known phase CT secondary should be compared with the associated phase to neutral VT secondary voltage. The phase angle between them should be measured, and should relate to the power factor of the system load.

If the three-phase voltage transformer has a broken-delta tertiary winding then a check should be made of the voltage across the two connections from the broken delta  $V_N$  and  $V_L$ , as shown in Figure 23.22. With the rated balanced three-phase supply voltage applied to the voltage transformer primary windings, the broken-delta voltage should be below 5 volts with the rated burden connected.

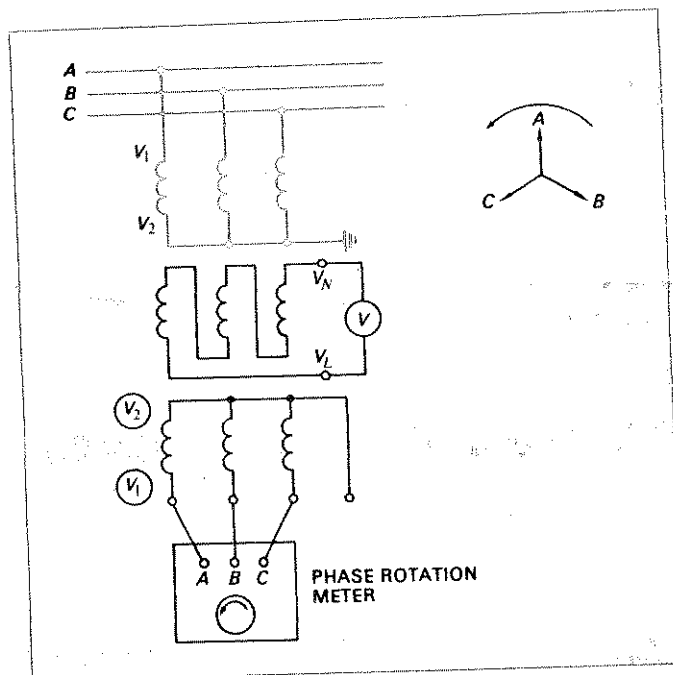


Figure 23.22 Voltage transformer phasing check.

## 23.17

### SECONDARY INJECTION

These tests and the equipment necessary to perform them are generally described in the manufacturer's manuals for the relays, but brief details are given below for the main types of protective relay.

#### 23.17.1

##### Secondary injection equipment

It has been common practice to provide test blocks or test sockets in the relay circuits so that connections can readily be made to the test equipment without disturbing wiring; see Figure 23.23. A later development was the test plug shown in Figure 23.24, which can be used to plug either into a drawout relay case or into a test block mounted near to a non-drawout relay case; see Figure 23.25.

When used with a drawout relay in the manner shown in Figure 23.24, the multiple fingers of the test plug are inserted between the contact strips of the case and the drawout chassis, which are normally sprung together to make firm contact.

Since the top and bottom contact of each test plug finger is separated by an insulating strip, the relay circuits can be completely isolated from the switchgear wiring when the

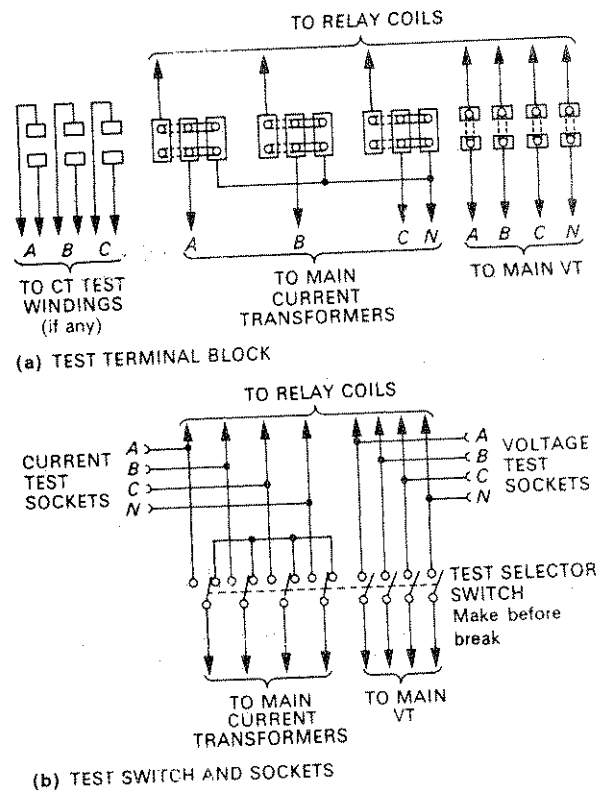


Figure 23.23 Test block and sockets.

test plug is inserted. It must be remembered, however, that the current transformer shorting switches, fitted to the drawout chassis to prevent the current transformers becoming open-circuit if the relay is ever withdrawn on-load, remain open-circuit when the test plug is inserted. It is therefore essential that CT shorting jumper links are fitted across all appropriate 'live side' terminals of the test plug BEFORE it is inserted. With the test plug inserted in position, all the test circuitry can now be connected to the isolated 'relay side' test plug terminals. Where a double-ended drawout case is employed, two such test plugs may be necessary.

Withdrawing the test plug immediately restores the connections to the main current transformers and voltage transformers, removes the test connections, and also the short circuits which had been applied to the main CT secondary circuits.

A more recent development has been the testing facilities provided for the modular type case shown in Figure 23.26. The heavy current connectors at the extreme right hand side of the case are normally connecting the main a.c. and d.c. incoming supplies to the relay and hold open short-circuiting switches provided in the case to prevent CT secondary circuits from being open circuited.

When these connectors are removed, the relay is isolated and the main current transformer incoming connections are automatically short-circuited.

A test plug may then be inserted, as shown in Figure 23.27, so that secondary injection tests can be carried out as previously described for the drawout case. This test plug is similar to the one previously described but is specially adapted to suit the modular housing shown. It is used in an identical manner.

Withdrawing the test plugs from the modular case merely re-applies the CT shorting switches and removes the test connections from the relay. Replacement of the heavy current connectors restores the incoming a.c. and d.c. supplies to the relay and also removes the short circuits from the main current transformers.

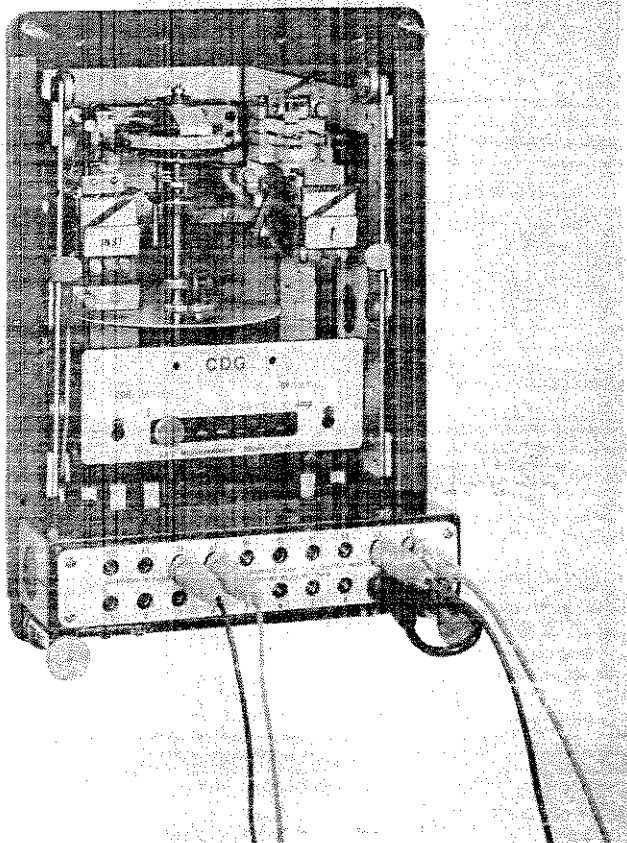


Figure 23.24 Test plug in drawout relay.

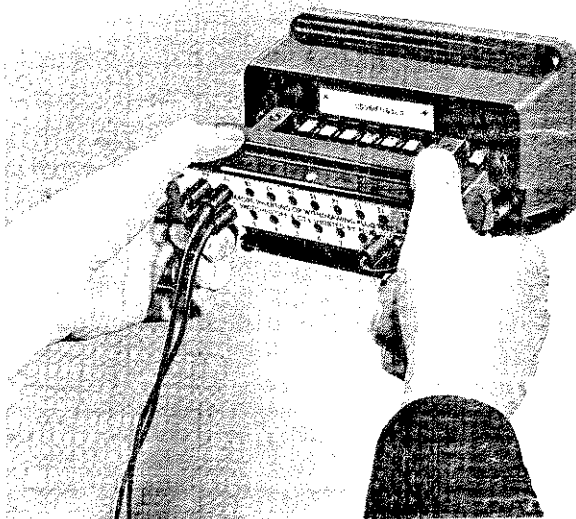


Figure 23.25 Test block and plug.

Where several relays are used in a protective scheme one or more test blocks may be fitted on the relay panel enabling the whole scheme to be tested rather than just one relay at a time. This is illustrated in Figure 23.28 showing a feeder protection scheme using MIDOS drawout relays.

The test block shown, type MMLG, is in a standard size 2 MIDOS case. It is normally mounted on the right hand side of a subrack or scheme of protective relays and caters for the isolation and monitoring of 14 conductor paths.

Although designed within the MIDOS range, this test block offers facilities for the monitoring and secondary

injection testing of any power system protection scheme. The test block may be used either with a multi-fingered test plug (type MMLB01) to allow isolation and monitoring of all the selected conductor paths, or with a single finger test plug (type MMLB02) which allows the currents on individual conductors to be monitored, as shown in Figure 7.21.

In keeping with the other MIDOS relays which may be coupled together mechanically to form an overall scheme, the MIDOS test block is provided with a cover, to protect the test access points. A feature of this cover is that a metallic probe is mounted on its underside, such that when the cover is in position the probe completes a connection between terminals 13 and 14. By using this circuit for one of the d.c. auxiliary supply lines, the d.c. supply to the relay is disconnected when the cover is removed, so minimizing the chance of inadvertent spurious tripping. Removal of the black cover also exposes the bright orange face-plate of the block, clearly indicating that the protective scheme is in an 'out-of-service' test state.

The type of the relay to be tested determines the type of equipment used to provide the secondary injection currents and voltages. The current coil impedance of many relays is non-linear; this can cause the test current waveform to be distorted if the injection supply voltage is fed directly to the coil. The presence of harmonics in the current waveform may affect the torque of the relay and give unreliable test results, so in most injection test sets the current supply is controlled by an adjustable series reactance, which keeps the power dissipation small and the equipment light and compact.

Many test sets are portable and include precision ammeters and voltmeters and timing equipment. Details of typical test sets are given below in the sections on the different types of relays.

### 23.17.2

#### Overcurrent and earth fault relays

A typical test set for overcurrent relays is shown in Figures 23.29 and 23.30. The current is controlled by means of tapped reactors in the primary circuit of the injection transformer. The injection transformer is provided with secondary tapplings chosen to correspond with the current setting of the relay. This ensures that the relay impedance is small when reflected back into the primary circuit of the injection transformer, and reduces the harmonics in the test current that are due to saturation of the magnetic circuit of the relay under test. The test set incorporates a digital timer with alternative setting ranges of 0.1 ms to 10 s or 1 ms to 100 s, which enables modern overcurrent relays of the inverse definite minimum time type to be checked most accurately.

When using the set, the test current should first be set approximately with the relay coil shorted out to prevent unnecessary heating. The coil can then be unshorted for the final adjustment of the test current. Instantaneous overcurrent relays should be checked as follows:

- i. Measure the minimum current that gives operation at each current setting.
- ii. Measure the maximum current at which resetting takes place.
- iii. Check the correct functioning of the plug-bridge short-circuiting device.

To check the performance of inverse time or definite time relays the above tests for instantaneous relays may be performed in full, but it is more usual for tests (i) and (ii) to be performed at the maximum and minimum settings and finally at the chosen setting. In addition:

- iv. Measure the operating time at suitable values of current and check the time/current curve at two or three points with the time multiplier setting TMS at 1.
- v. Measure the resetting time at zero current with the TMS at 1.

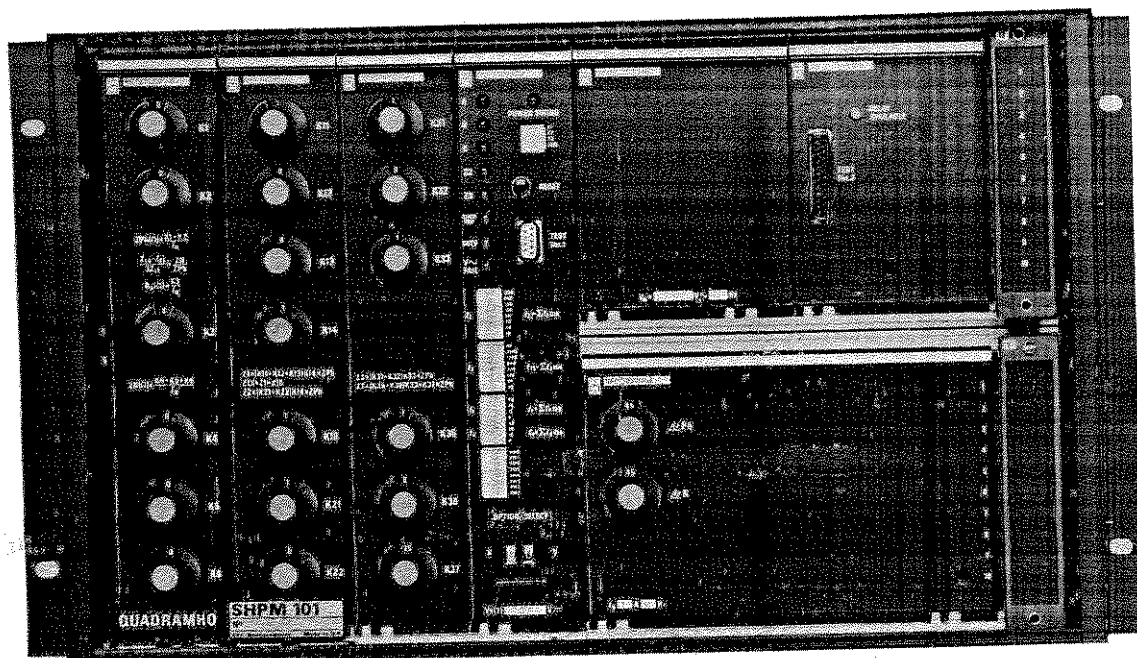


Figure 23.26 Distance scheme in modular case.

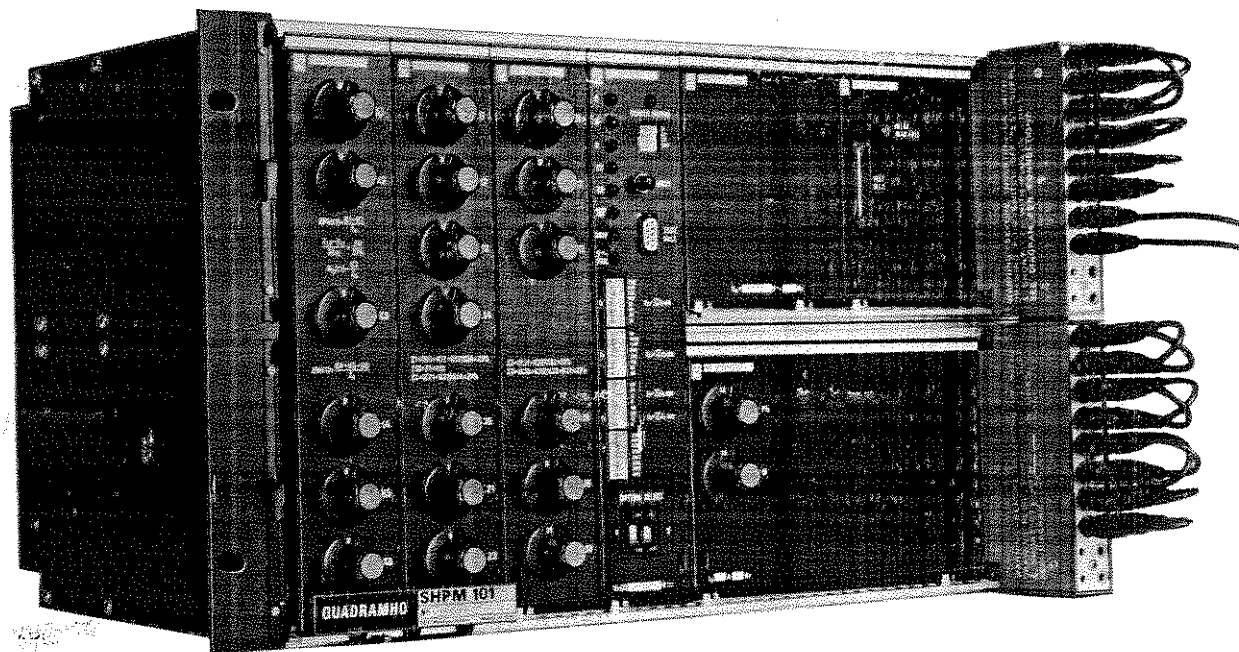


Figure 23.27 Test plugs in modular case.

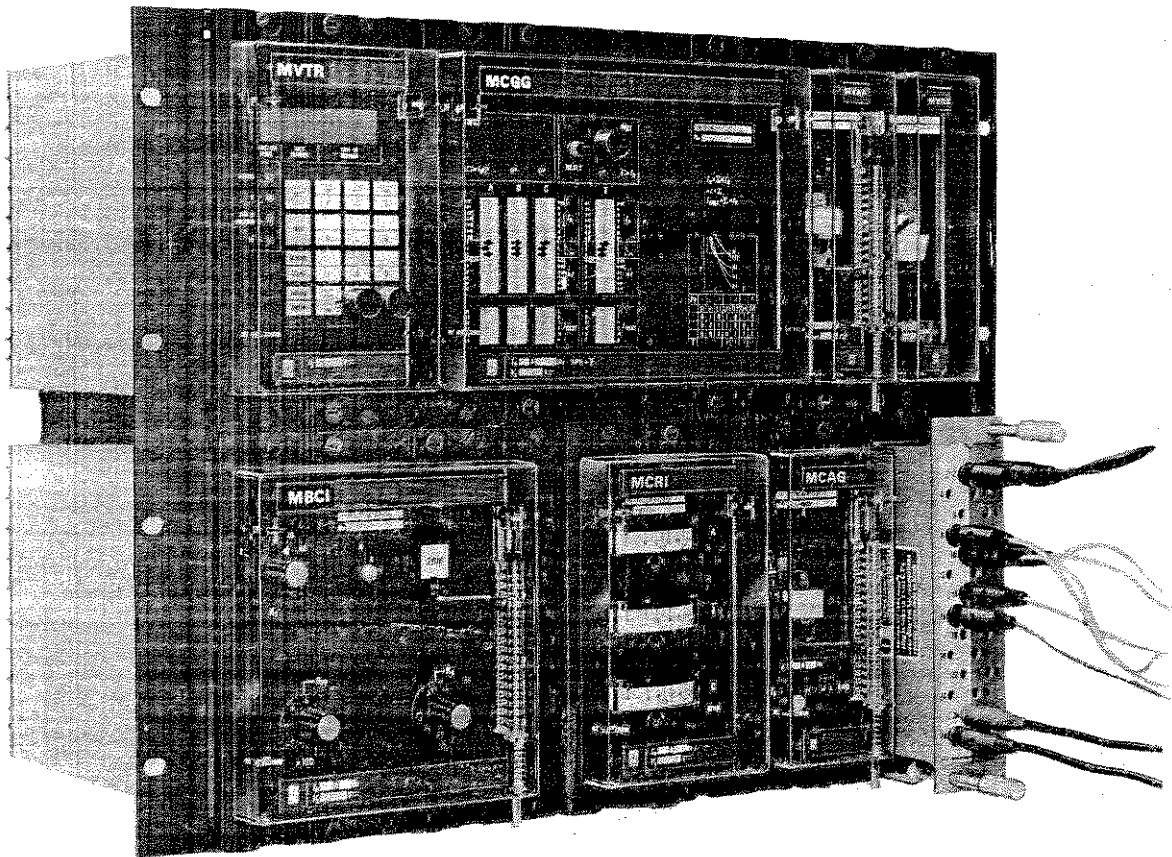


Figure 23.28 MIDOS feeder protection with test plug inserted for scheme and relay testing.

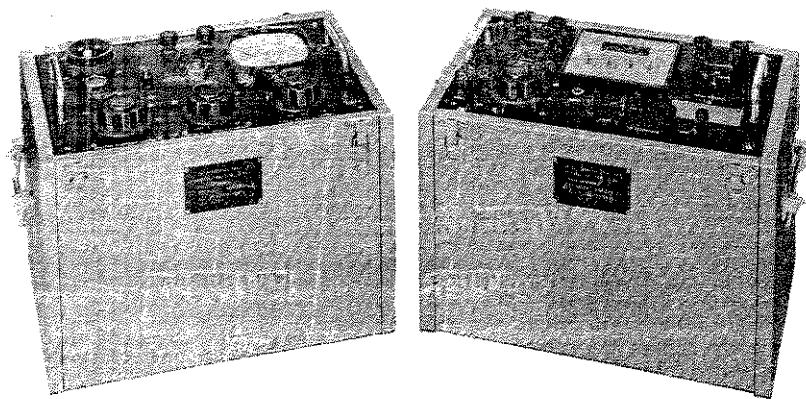
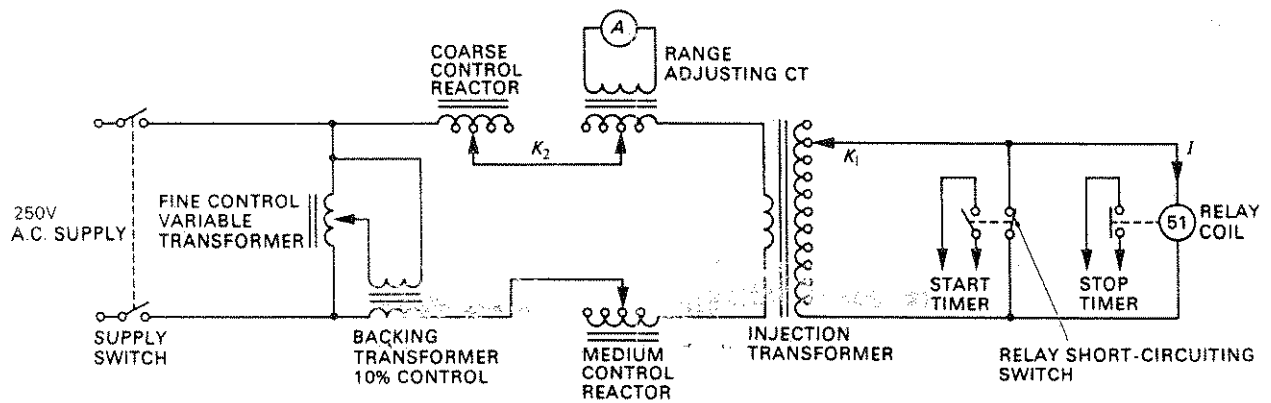


Figure 23.29 Overcurrent test set.



$$\text{RELAY CURRENT } I = \text{AMMETER READING (A)} \times K_1 K_2$$

Figure 23.30 Circuit diagram of overcurrent test set.

tests (iv) and (v), the coil is shorted out after the final setting of the current, the test set timing device is reset, the relay once more unshorted and put in circuit. The shorting switch starts the timing device and the operating coil, the relay contacts stops it, leaving the relay operating time registered on the timer dial.

### 23.17.3 Differential relays

The sensitivity of differential relays can be checked with the overcurrent test set described above. It might be argued that these secondary injection tests are not necessary, as the sensitivity is checked again later by primary injection. Secondary injection is nevertheless recommended, because the recorded figures form a reference for future routine maintenance checks on the relay, and also because if the relay is faulty, it is better to find this out during a simple secondary injection test rather than when a primary injection test is being carried out, as the latter sometimes takes a great deal of organizing.

When testing unbiased differential relays, the current settings should be checked using the overcurrent test set, slowly raising the current until the relay operates. This should be done at all the current settings and finally at the required setting. The results should be recorded for future reference and they should agree approximately with the manufacturer's declared current setting.

The current settings of generator or transformer biased relays should be checked as above with the overcurrent test set. Injection should be made into one bias coil and out of the operating coil, as shown in Figure 23.31.

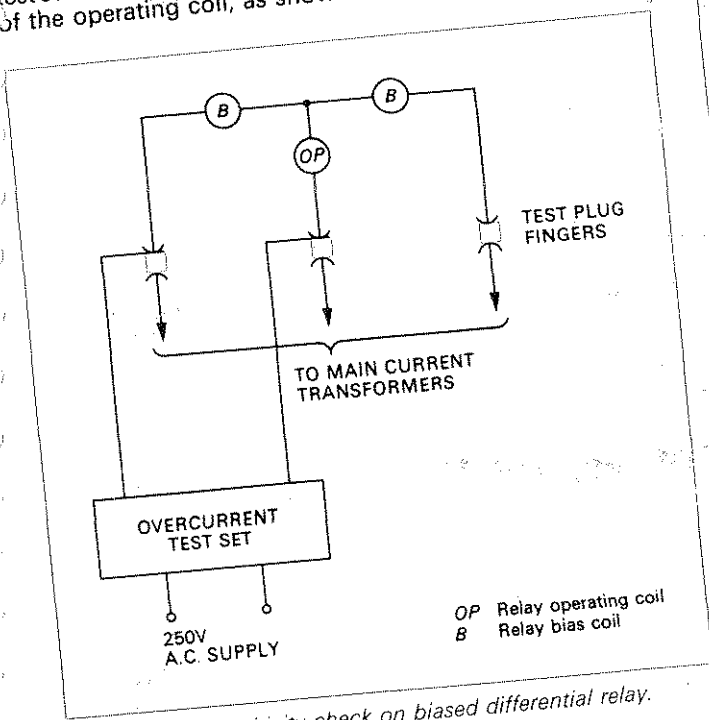


Figure 23.31 Sensitivity check on biased differential relay.

In addition to this, a check can be made at one or more points on the bias characteristic with the over-current test set, as shown in Figure 23.32(a). The current selector switches should be set to give the approximate total current required, that is, the bias current plus the operating current.

Resistance  $R$  should be set to zero, and the current then applied. The resistance  $R$  should then be increased until the split-up of through current and operating current just causes the relay to operate. The ratio of operating current (measured by ammeter  $A_1$ ) to through current (measured by ammeter  $A_2$ ) should approximate to the value at the corresponding point on the manufacturer's published bias curve for the relay. The bias of the relay can be checked in

this manner up to approximately 100% of the operating current. Beyond this point, saturation in the operating coil current distorts the current waveform and gives unreliable test results. If higher bias check points are required, the circuit shown in Figure 23.32(b) must be used, with series resistors  $R_1$  and  $R_2$  to control the current from the local mains supply. However, a check at five times rated through current is usually quite sufficient to prove the relay bias curve.

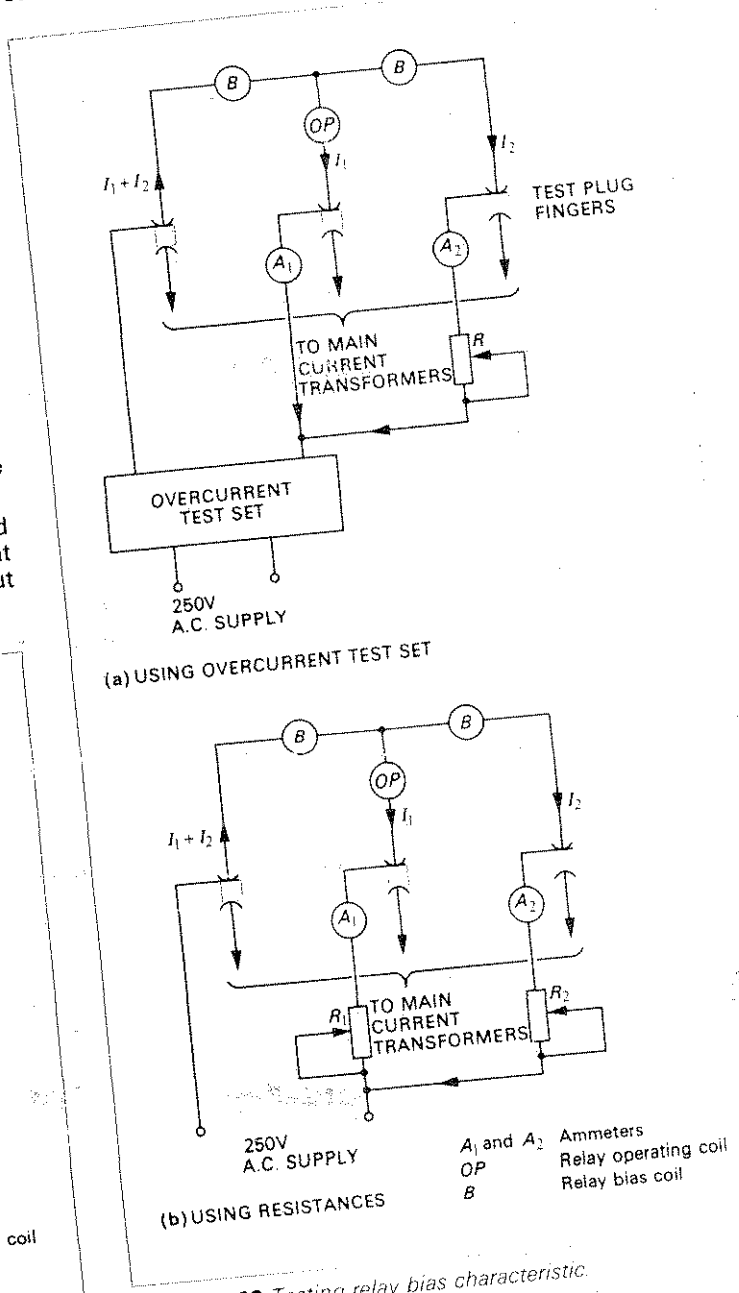


Figure 23.32 Testing relay bias characteristic.

### 23.17.4 Pilot wire relays

The various current settings for pilot wire relays can be checked using the overcurrent test test. To obtain the correct settings, the pilot wires must be connected to the relays at each end of the line and the correct pilot compensation must be set on the relays.

The current settings of the relays may then be checked by the injection into each phase in turn; see Figure 23.33(a). The results obtained should approximate to the manufacturer's declared current setting for the length and type of pilots in use. The stability of the protection can be checked by using the feeder conductors to connect the summation current transformers at each end of the feeder in series. Secondary

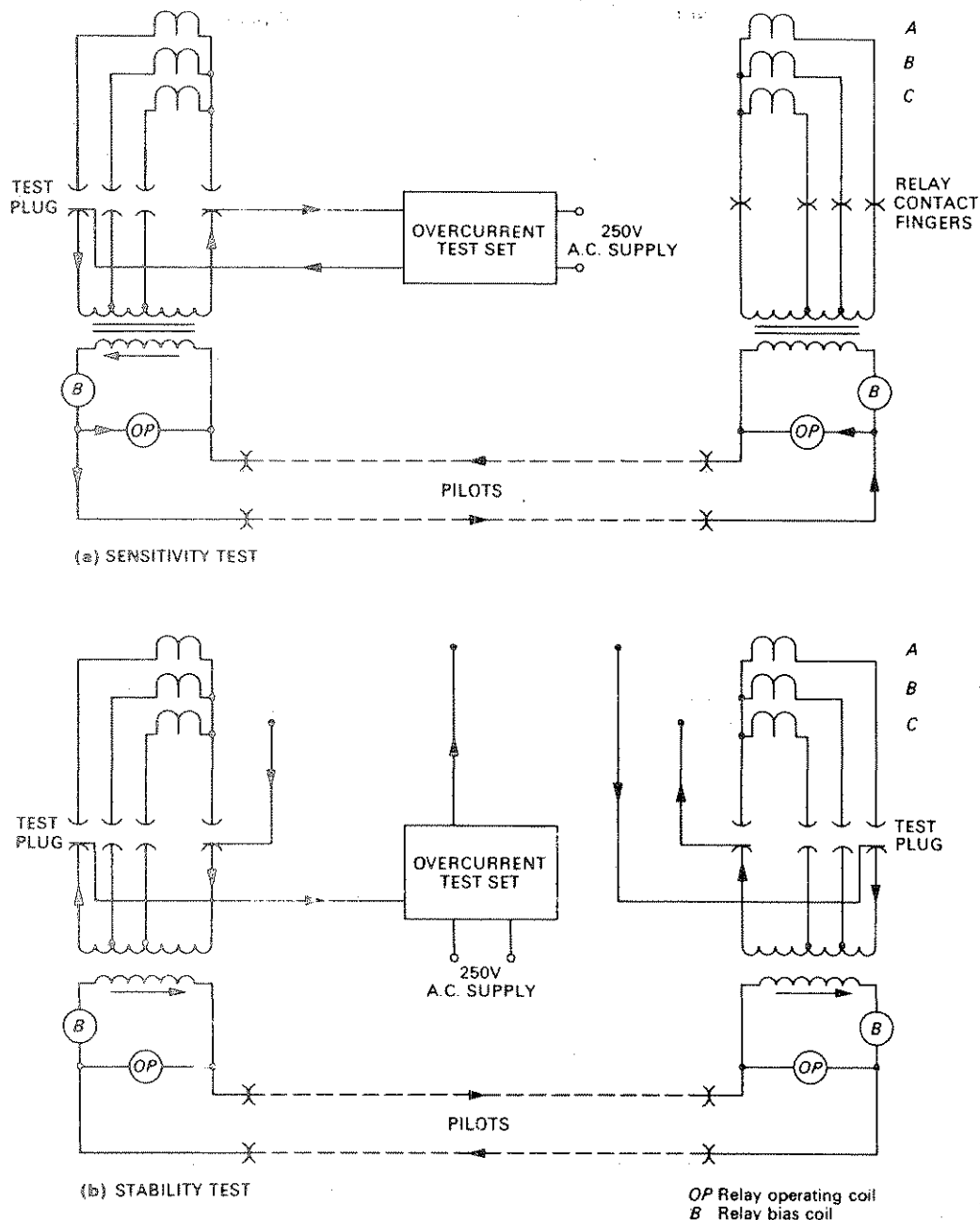


Figure 23.33 Testing pilot wire relay.

injection can then be made as shown in Figure 23.33(b), the current circulating through the feeder conductors, summation transformers and pilot wires. Several times the relay rated current can be made to circulate through the summation transformer primaries; a corresponding current circulates through the pilots. This test is very useful, as it is practically impossible to produce the same magnitude of circulating current in the pilots when carrying out the primary injection end-to-end tests described later.

#### 23.17.5

##### Negative phase sequence relays

The current setting of this type of relay is usually expressed in terms of negative phase sequence current only. This current setting can be checked with the overcurrent test set by injection into the relay. If the relay is provided with an external filter network, injection must be made at the test block connected between the main current transformers and filter units; see Figure 23.34.

The relay is checked by injecting into each pair of phases

in turn; since this simulates phase to phase fault conditions, only  $1/\sqrt{3}$  of the injected current is negative phase sequence current. If the relay has an inverse time/current characteristic, points on the curve can be checked as previously described for the standard inverse time overcurrent and earth fault relays.

#### 23.17.6

##### Directional relays

The directional characteristics of many types of relays can be checked with the equipment shown in Figure 23.35. This method uses a phase shifting transformer, permitting the phase angle of the relay voltage to be varied with respect to the relay current, enabling the directional characteristic and maximum torque angle of the relay to be checked. The relay must have directional properties for ranges of both current and voltage, and with standard inverse time directional overcurrent relays, for example, test voltages of 100% and 3% rated voltage together with a test current of 100% rated current should be used.



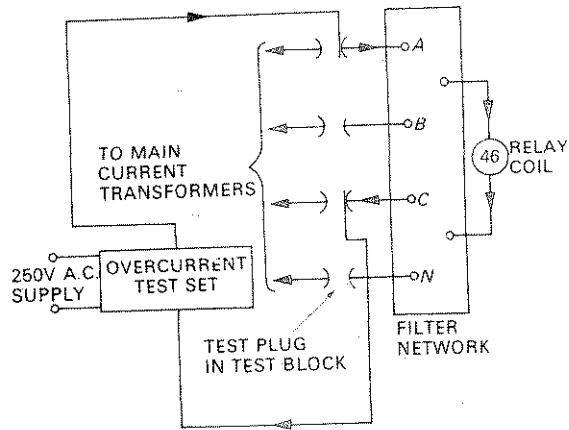


Figure 23.34 Testing sensitivity of negative phase sequence relay.

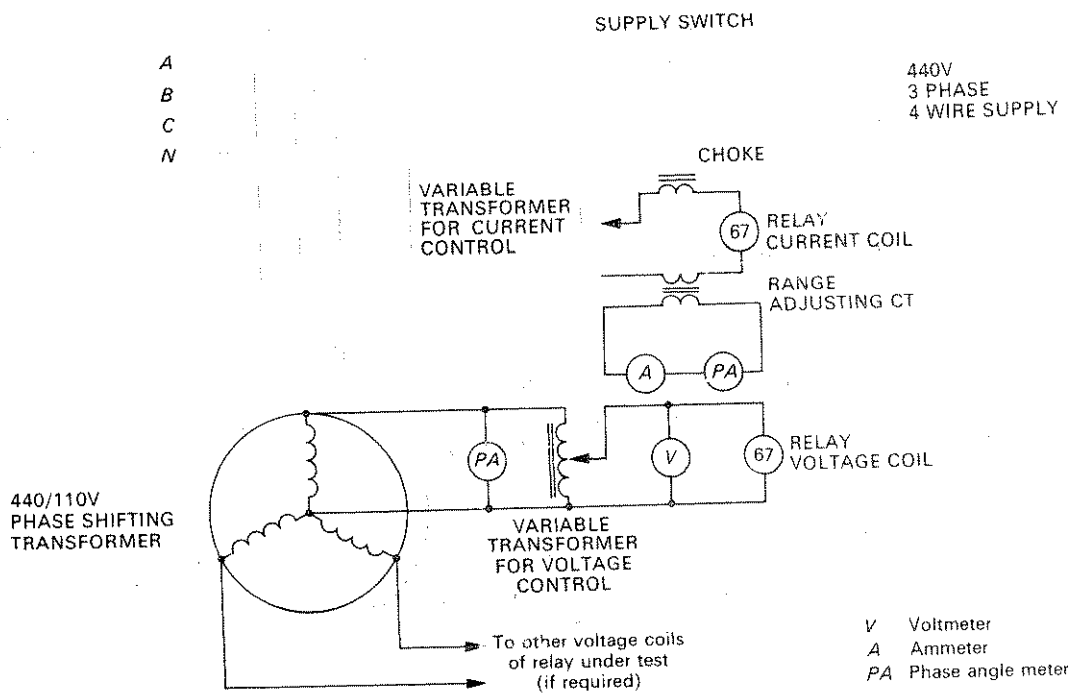


Figure 23.35 Test equipment for directional relays.

It is important to keep the phase angle meter working near to its rated voltage and current to maintain accurate results. For this reason the voltage coil connection is made to the primary circuit of the variable voltage transformer, which generally has negligible phase angle error.

### 23.17.7 Distance relays

Distance relays are required to measure impedance accurately over wide ranges of voltage and current. The impedance measurement of these relays can be checked with the type of equipment shown in Figure 23.35, as used for directional relays. This form of equipment, however, only checks the measuring accuracy of the relay under static conditions, that is, the current is increased slowly or the voltage is decreased slowly until the relay operates. When a fault occurs on the system being protected, the relay voltage falls immediately from the nominal value to the fault voltage, while the current instantaneously rises from some load value or zero to the fault value. Both these

sudden changes in magnitude are accompanied by changes in phase angle.

Test equipment that gives a more realistic simulation of these fault conditions is shown in Figures 23.36 and 23.37.

The equipment is connected so as to represent actual system conditions. With the supply switches closed and the fault contactor in the unoperated condition, the normal working voltage is applied to the selected relay via the voltage auto-transformer. When the fault contactor is operated the fault current  $I_F$  is applied to the selected relay via the range adjusting current transformer. At the same instant, the voltage applied to the relay collapses to the fault voltage  $V_L$ , the magnitude of  $V_L$  depending on the ratio of the source impedance to the line impedance ( $Z_s/Z_L$ ). The voltage auto-transformer has 10% and 1% tapings to allow the line impedance  $Z_L$  to be matched to the relay ohmic setting. By varying the source impedance  $Z_s$  the relay ohmic setting can be checked over a wide range of voltage and current magnitudes.

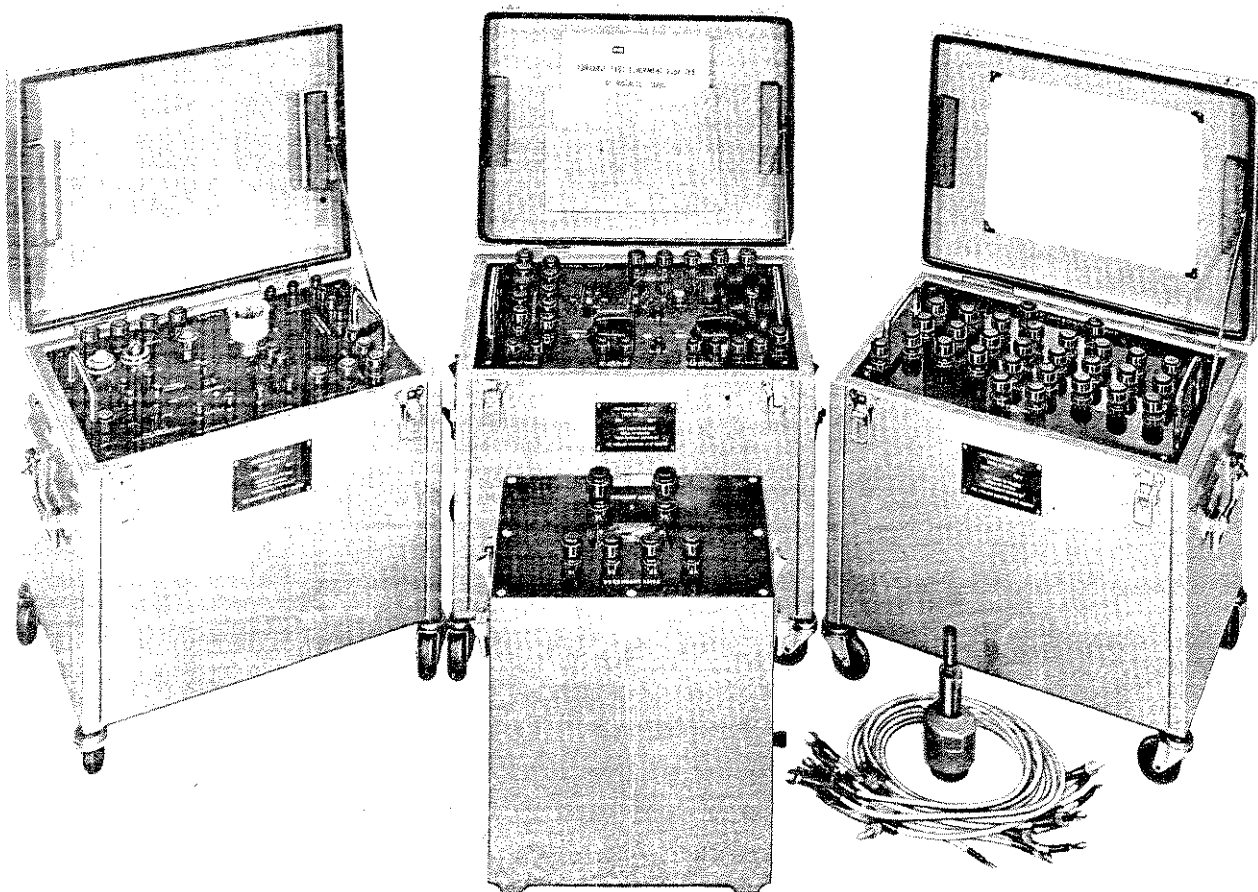


Figure 23.36 Portable test equipment type ZFB for distance relays.

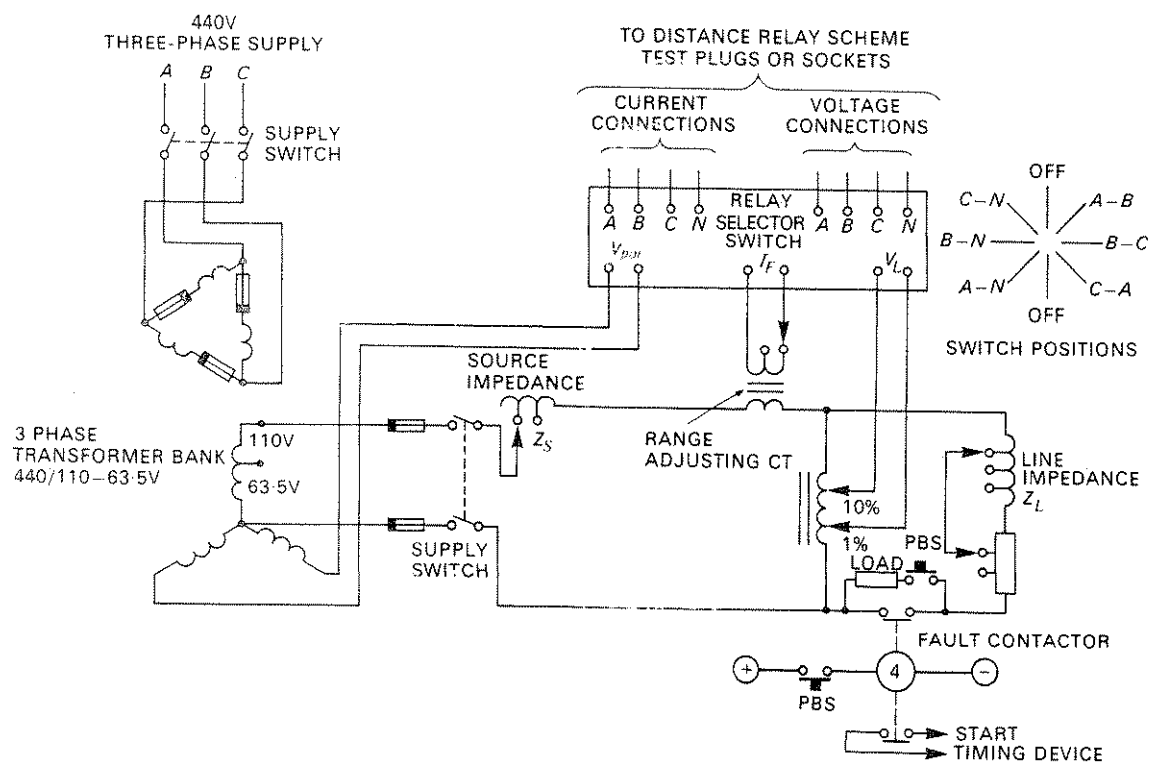


Figure 23.37 Test equipment for distance relays.



It is usual to check the relay ohmic setting at the actual line angle. The choke and resistance tappings of the line impedance  $Z_L$  are provided for this purpose. In order to check the characteristics of mho or reactance relays, angles other than the line impedance angle may be chosen. The points usually checked on mho and reactance relay characteristics are shown in Figure 23.38.

If it is so desired, load current can be applied to the relays before the fault condition by operating the load push-button just before operating the fault contactor. Operation of the fault contactor short-circuits the load resistance and presents only the line impedance  $Z_L$  to the relay. The use of a relay selector switch avoids any human error that might otherwise occur when changing the voltage and current connections from one measuring relay in the scheme to another. By injecting into the scheme through the secondary voltage and current connections, the whole distance scheme is made to perform, the secondary wiring between relays is checked, and all associated auxiliary relays are made to operate.

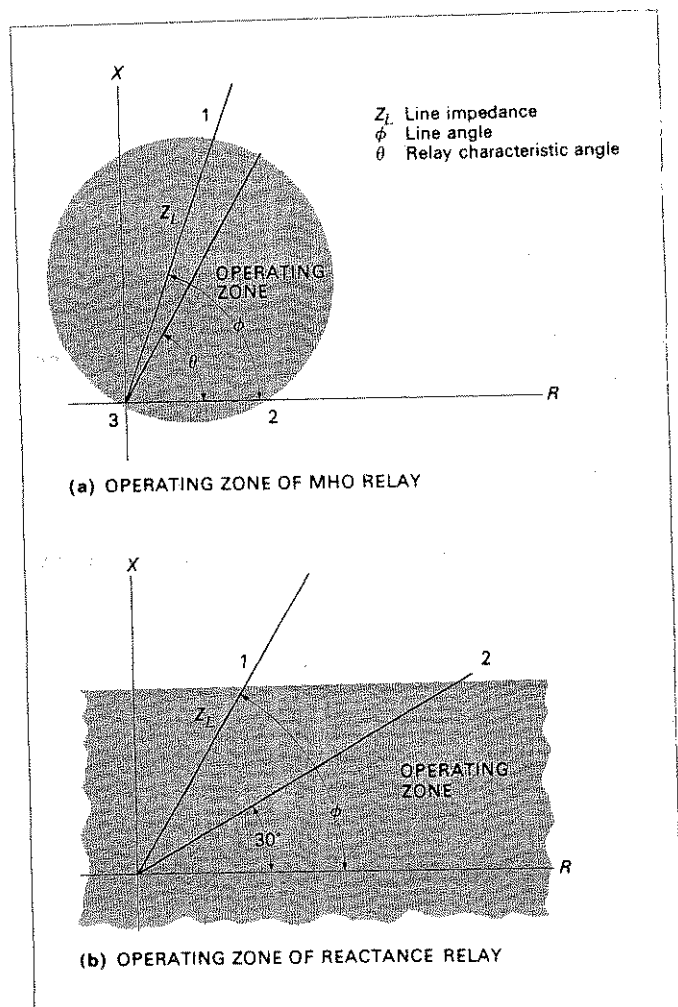


Figure 23.38 Characteristic of distance relays.

### 23.17.8

#### D.c. operated relays

Master and auxiliary tripping relays and other d.c. operated relays should be tested for correct operation down to 60% of normal voltage by injection at suitable test points or at the relay terminals.

### 23.18

#### PRIMARY INJECTION

This type of test involves the entire circuit; current transformer secondaries, relay coils, trip and alarm circuits, and all intervening wiring are checked. There is no need to

disturb wiring, which obviates the hazard of open-circuiting current transformers, and there is generally no need for any switching in the current transformer or relay circuits.

An alternator is the most useful source of power for providing the heavy current necessary for primary injection. If there is one available with spare busbars, many types of protection can be tested satisfactorily, but such amenities are seldom available on a power system.

Primary injection is usually carried out by means of a portable injection transformer (Figure 23.39), arranged to operate from the local mains supply and having several low voltage heavy current windings. These can be connected in series or parallel according to the current required and the resistance of the primary circuit.

The injection transformer is usually rated at about 10 kVA and has a ratio of 250/10 + 10 + 10 + 10 volts. This permits currents of up to 1000 A to be obtained with the four secondary windings in parallel and up to 250 A with the windings in series. The best method of controlling the injection transformer current is to use a tapped reactor similar to that in a secondary injection equipment, or a heavy current (40 A) variable auto-transformer. The use of resistors for current control causes a great deal of power to be dissipated unnecessarily.

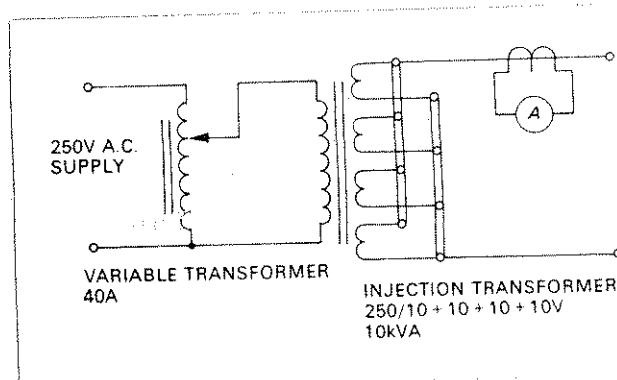


Figure 23.39 Primary injection test set.

If the main current transformers are fitted with test windings, these can be used for primary injection instead of the primary winding. The current required for primary injection is then greatly reduced and can usually be obtained from the less cumbersome secondary injection equipment shown in Figures 23.29 and 23.30. Unfortunately, these test windings are not always provided, because of space limitations in the main current transformer housings.

### 23.18.1

#### Overcurrent and earth fault relays

If the equipment includes directional, differential or earth fault relays, the polarity of the main current transformers must be checked. The circuit for checking the polarity with a single-phase test set is shown in Figure 23.40. A short circuit is placed across the phases of the primary circuit on one side of the current transformers while single-phase injection is carried out on the other side. The ammeter connected in the residual circuit will give a reading of a few milliamperes with rated current injected if the current transformers are of correct polarity, but a reading proportional to twice the primary current if they are of wrong polarity. Because of this, a high-range ammeter should be used initially, for example one giving full scale deflection for twice the rated secondary current. If an earth fault relay with a low setting is also connected in the residual circuit, it is advisable temporarily to short-circuit its operating coil during the test, to prevent possible overheating. The single-phase injection should be carried out for each pair of phases. If the main current transformers are used solely for overcurrent protection, the polarity tests previously described are unnecessary.

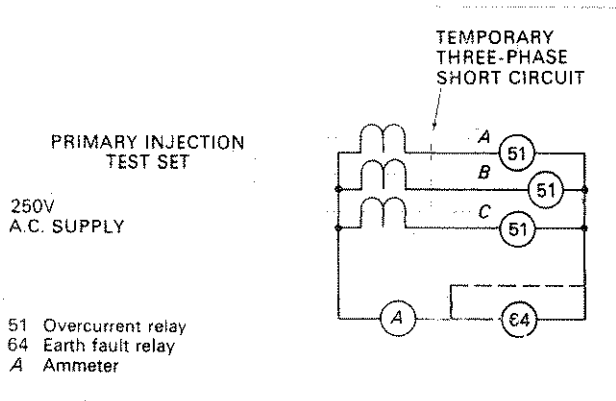


Figure 23.40 Primary check on main current transformers.

Because the amount of primary current available is limited, the operating time of the relay cannot be checked at high currents. It is usual to obtain a primary current of about 1.5 to 2.0 times the current setting of the relay. The relay torque is relatively small at this current level and the effect of any foreign matter in the moving parts of the relay is very noticeable. While phase to phase injection is satisfactory for checking the overcurrent relays, single-phase injection (Figure 23.41) should be used to check the earth fault setting of residually connected relays.

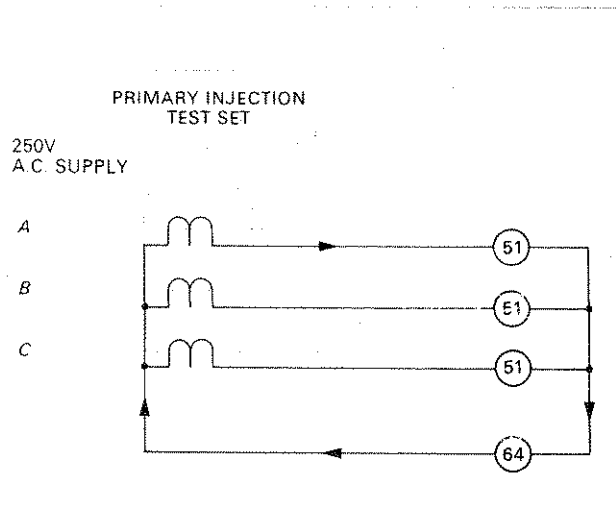


Figure 23.41 Sensitivity test on earth fault relay.

### 23.18.2 Directional relays

The most satisfactory method of checking the directional feature of directional overcurrent, distance and other types of wattmetric relays is to use the load current.

With phase fault directional overcurrent relays, the tests should be made when the load current is appreciable and its direction is in no doubt. The relay contacts should close when the load current is in the operating direction and open when the load current is in the reverse direction. The direction of the load current to the relay can be reversed by cross-connecting the voltage or current leads of the test plug, as shown in Figure 23.42; this avoids interfering with the cubicle wiring and ensures that the connections are restored correctly. These tests alone are not conclusive, and it is therefore recommended that the power factor presented to the relay be measured during the load test (Figure 23.43) with a phase angle meter.

Earth fault directional overcurrent relays are usually energized from the broken-delta winding of a three-phase voltage transformer and the residual circuit of the main current transformers. Under normal load conditions this type of relay is not energized, and it is therefore necessary to

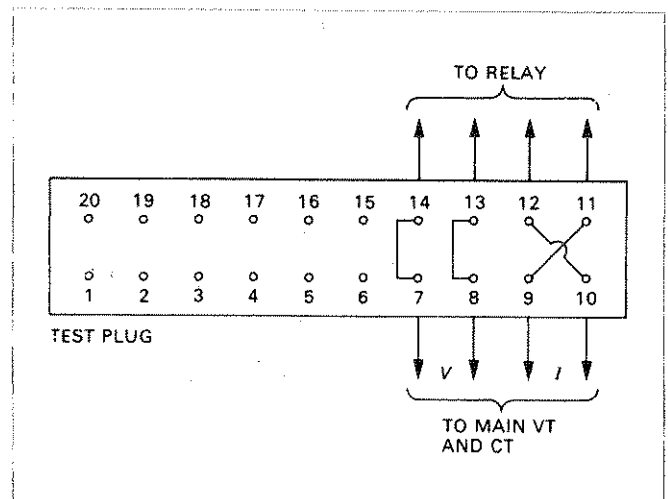


Figure 23.42 Test plug link connections to reverse current seen by relay.

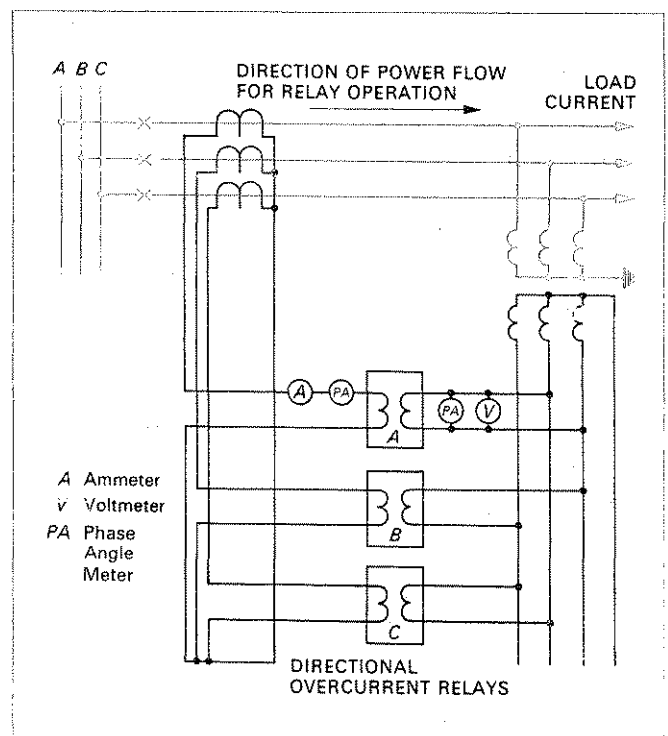


Figure 23.43 Load test on directional overcurrent relays.

simulate operating conditions; one phase of the voltage transformer primary is disconnected and short-circuited while the current transformers of the other two phases are disconnected and short-circuited (Figure 23.44). This simulates an earth fault on the phase from which the voltage transformer is disconnected.

With load current flowing in the operating direction the relay contacts should close. Again, it is recommended that the power factor presented to the relay be measured during the test.

Mho relays can be made to operate with load current flowing in the operating direction by removing the restraint voltage from the relay. On most modern distance protection relays a convenient switch, plug or link is provided on the front of the relay to facilitate this test.

The removal of the restraint voltage from the mho relay changes the mho circle characteristic to a plain directional characteristic with the same relay characteristic angle, as

shown on Figure 23.45. With a lagging load flowing in the operating direction the relay will operate as soon as the restraint voltage is removed.

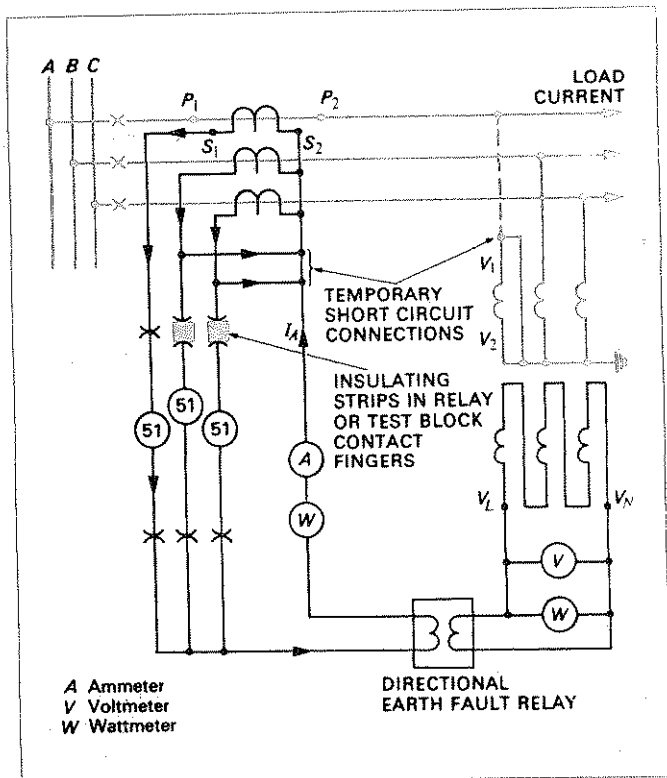


Figure 23.44 Load test on directional earth fault relay.

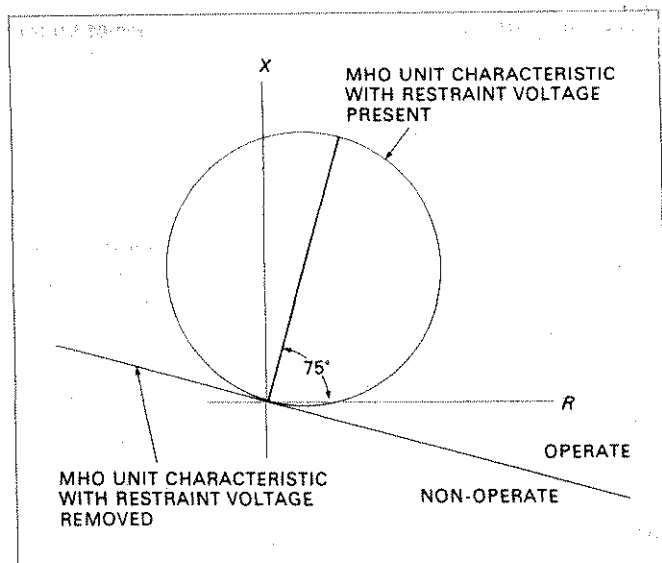


Figure 23.45 Directional characteristics of mho unit.

The relay should then be checked for non-operation for load flowing in the opposite direction. This can conveniently be done with a test plug inserted in the relay case, as shown in Figure 23.46, with the cross-over connections made to the relay current circuits so as, in effect, to reverse the current flow to the relay.

Should it be impossible to obtain a lagging power factor load down the protected line to carry out the directional test, in other words, if the load has a leading power factor (Figure 23.47), a power factor that lags as seen by the relay can be obtained by using the test plug inserted in the relay case as shown in Figure 23.48, that is, with the voltage connections rotated through 120° so that the phase A relay now receives the phase C voltage and hence a lagging power factor.

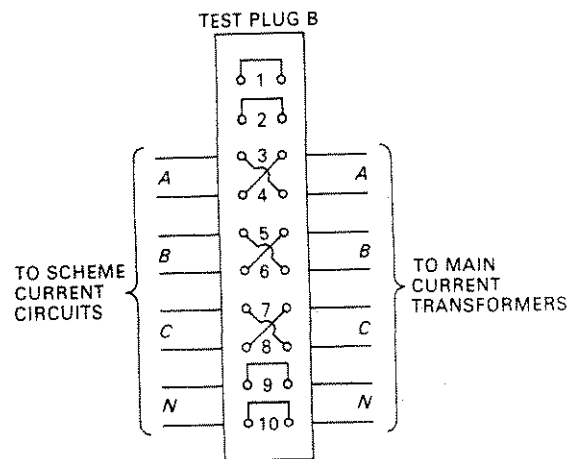


Figure 23.46 Diagram showing cross-over connections on test plug B to reverse load current to relay.

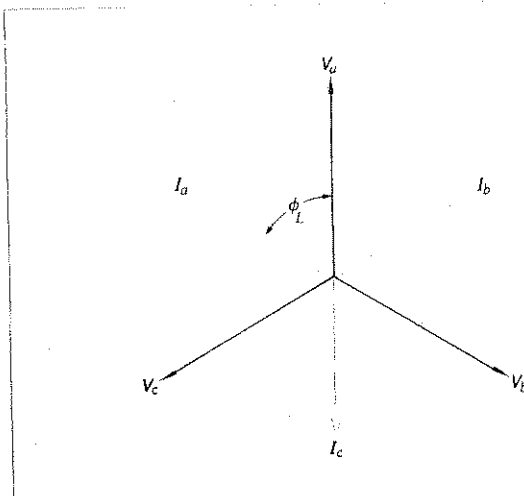


Figure 23.47 Leading power factor load.

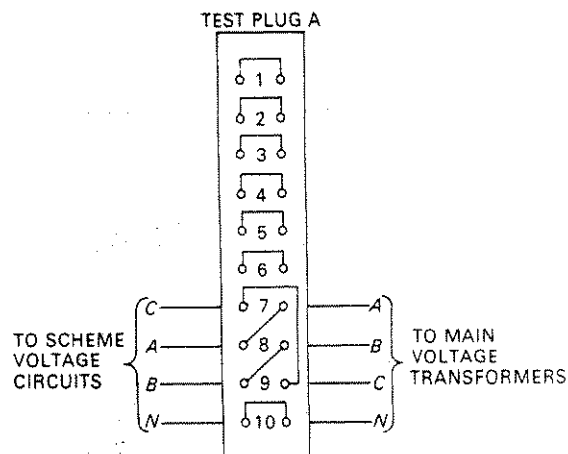


Figure 23.48 Rotation of voltage connections to relay.

Another method of proving the directional feature of the mho unit is to raise the relay setting to maximum and then introduce the Zone 2 and 3 resistances into the restraint circuit. This will increase the relay ohmic setting to approximately 250 ohms (1A relay), and, if the load current is lagging, it will be found that the relay can be made to operate with only 30% of the full load current. The

amount of load current necessary to cause operation in the above method depends largely on the load phase angle and the relay maximum torque angle (Figure 23.49). Reactance relays will operate for faults on either side of the relaying point and may therefore be described as non-directional. It is still necessary, however, to check that the relay has an ohmic reach limit in the forward direction and an almost infinite reach in the reverse direction (Figure 23.50).

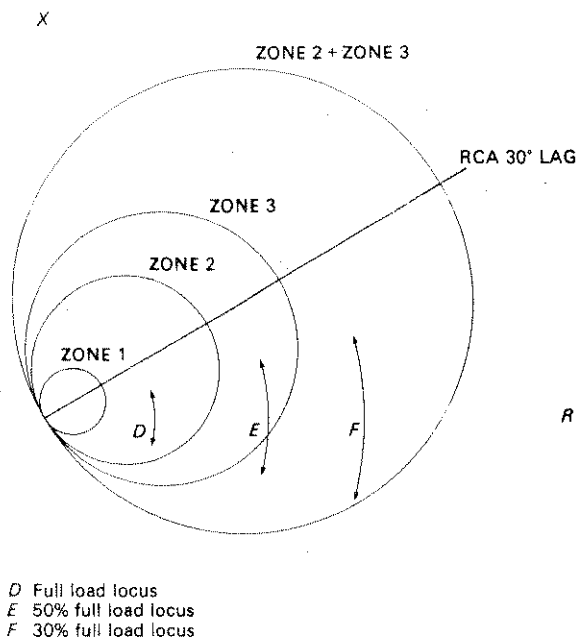


Figure 23.49 Direction check on mho relay using load current.

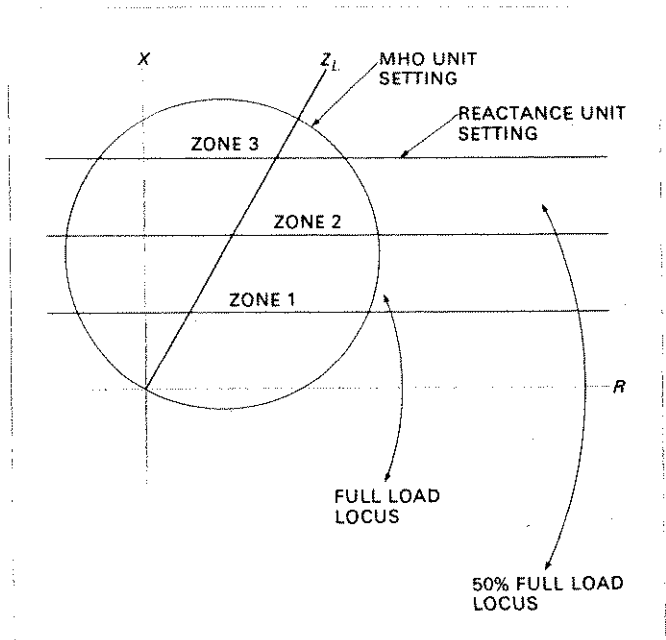


Figure 23.50 Check on reactance characteristic using load

In order to check that the relationship of the voltage and current applied to the reactance relay is correct, it is essential that the load power factor be lagging during the test. It should also be appreciated that reactance relays are normally controlled by a separate mho relay. It is therefore necessary to operate the mho unit, as previously described, before the reactance unit can operate. With load current flowing in the forward direction and at a lagging power factor, the reactance unit should not operate when the mho unit is made to operate. The subsequent removal of the restraint voltage from the reactance unit should cause immediate operation. If the voltage or current be of wrong polarity, the reactance unit will operate as soon as the mho unit is made to operate, that is, with the restraint voltage

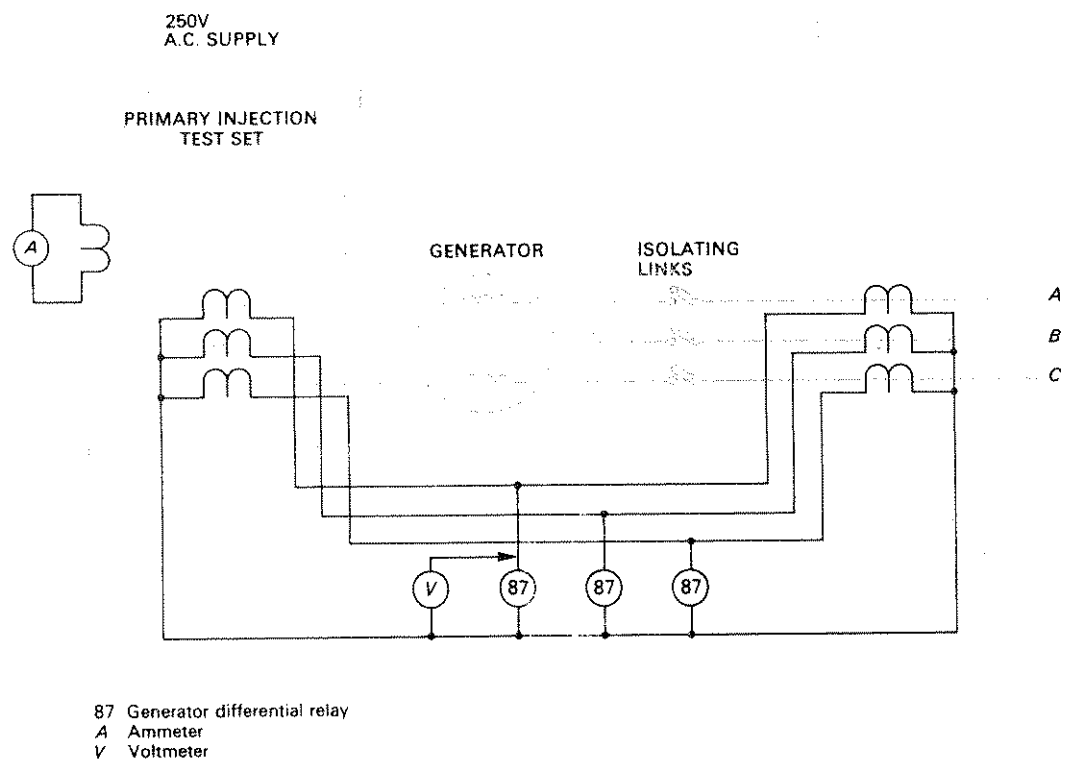


Figure 23.51 Testing sensitivity of generator differential protection using primary injection test set.

still applied to the reactance unit. It should be appreciated that this would also occur if the voltage and current connections were correct on the relay and the load power factor, as seen from the relaying point, were unity; hence the necessity for the test to be carried out with a lagging power factor load.

### 23.18.3 Generator differential protection

The sensitivity of this type of circulating current scheme can easily be checked by means of the primary injection test (Figure 23.51). Primary current is passed through one of the main current transformers and slowly raised until the relay just operates. This gives the true effective fault current necessary in the primary to cause operation and includes the relay current plus the magnetizing current of the current transformers shunting the relay. It is advisable while checking the sensitivity to measure the voltage across the relay coil and stabilizing resistance and so check the

approximate voltage developed by the main current transformer that causes relay operation. The sensitivity check should be carried out by injecting through the current transformer primary of each phase in turn to check all the units of the relay.

Another method of checking is to use the machine itself to supply the primary current, the current magnitude being carefully controlled by means of the machine excitation from a very low value up to that necessary to permit the required primary current.

With this method care must be taken since the suitability of the machine will depend upon the type of excitation circuit and the degree of control available.

In general, generators having d.c. rotating exciters usually have a hand operated d.c. field rheostat giving suitably smooth and continuous manual control over an adequate range of adjustment.

However, many brushless or self-excited generators have only a hand control on the automatic voltage regulator

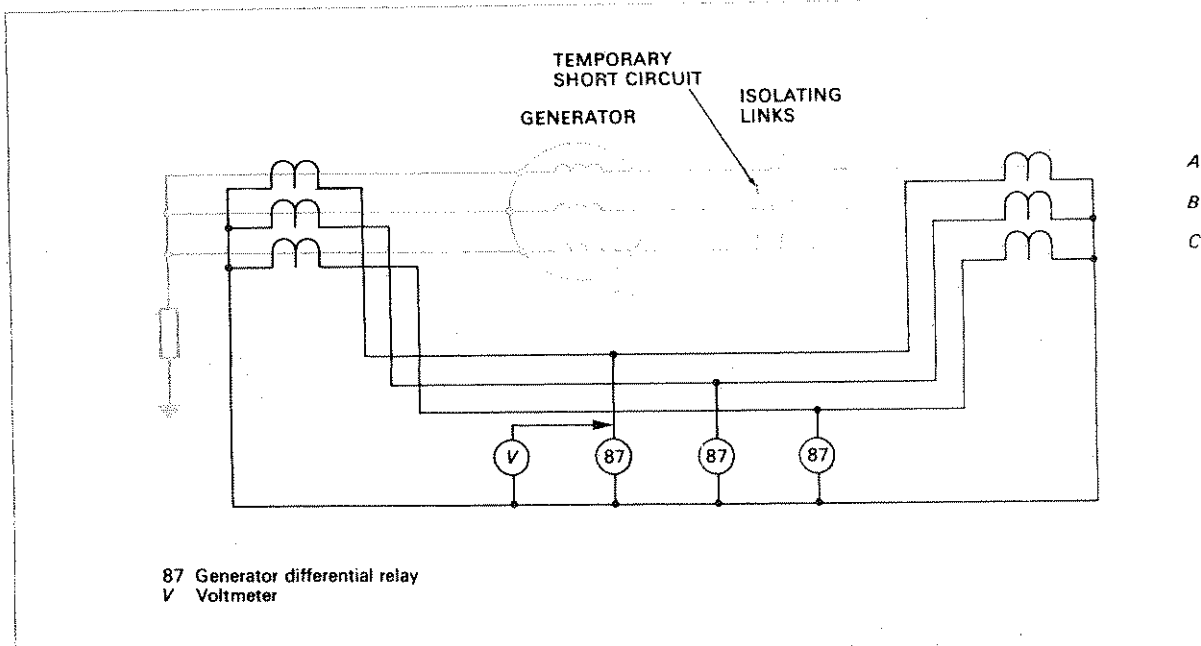


Figure 23.52 Testing sensitivity of generator differential protection using generator to supply primary current.

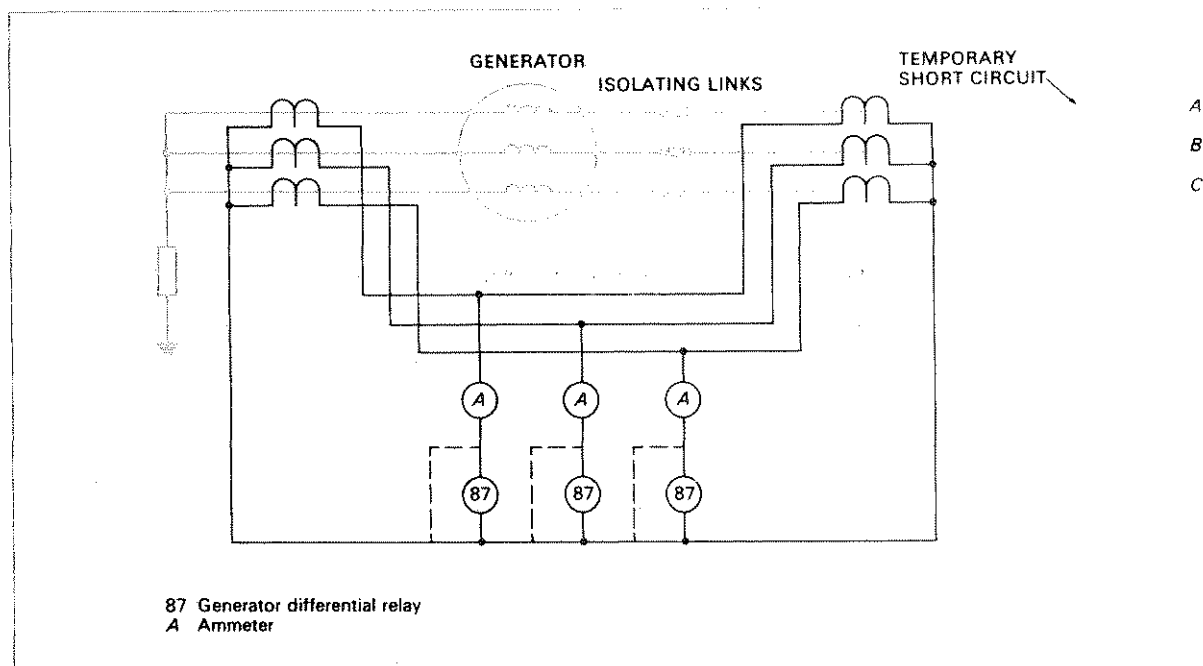


Figure 23.53 Checking stability of generator differential protection.

(AVR) giving a restricted variation around a nominal value, often no more than  $\pm 20\%$ .

So with this type of machine the AVR must be disconnected and a separate suitable source of controllable d.c. excitation used.

To check the differential protection sensitivity, the main circuit breaker is left open and a three phase short circuit is applied in the generator link cubicle to simulate an internal fault, as shown in Figure 23.52. The machine is then run up to speed and the excitation slowly raised until all three elements of the relay operate.

To check the stability of a generator differential protection scheme, the short circuit should be made on the busbar side of the main circuit breaker (Figure 23.53). The circuit breaker should then be closed and the machine excitation slowly raised again until full load current is circulating in the primary connections. The ammeters connected in series with the relay operating coils should be used initially on a range that will take twice the current transformer rated secondary current, and short circuits should be applied across the relay coils until it has been established that the main current transformers are connected correctly. Wrongly connected or open-circuited transformers will produce a substantial reading on the ammeters. If the ammeters do not indicate an out-of-balance current when full load primary current is circulating, a more sensitive ammeter range may be used to measure the spill current through the relay operating coils, which should be only a few milliamperes.

#### 23.18.4

##### Transformer biased differential protection

The sensitivity can be checked with the single-phase primary injection test set in the way described for generator differential protection. This test can be carried out by injecting through one current transformer to simulate earth faults or through two current transformers to simulate phase to phase faults (Figure 23.54).

To check the stability of the protection, full load current must be passed through the main current transformer primary windings. The best source of power for this test is a generator. If one of adequate current rating is available, the primary full load current can be made to circulate through the transformer by putting a three-phase short circuit on one side of the transformer external to the protection (Figure 23.55). The machine should then be coupled to the other side of the transformer, the generator run up to speed and the excitation slowly raised until full load current flows through the primary windings of the transformer. It should be appreciated that only 12% or less of the transformer winding rated voltage will have to be generated to make the full load primary current circulate.

If there is no machine available to circulate the full load current through the transformer, it may be possible to couple the transformer to local busbars that have a voltage rating of approximately 5% to 12% of one of the transformer windings. The transformer short-circuit impedance must be known, however, in order to calculate the busbar vol-

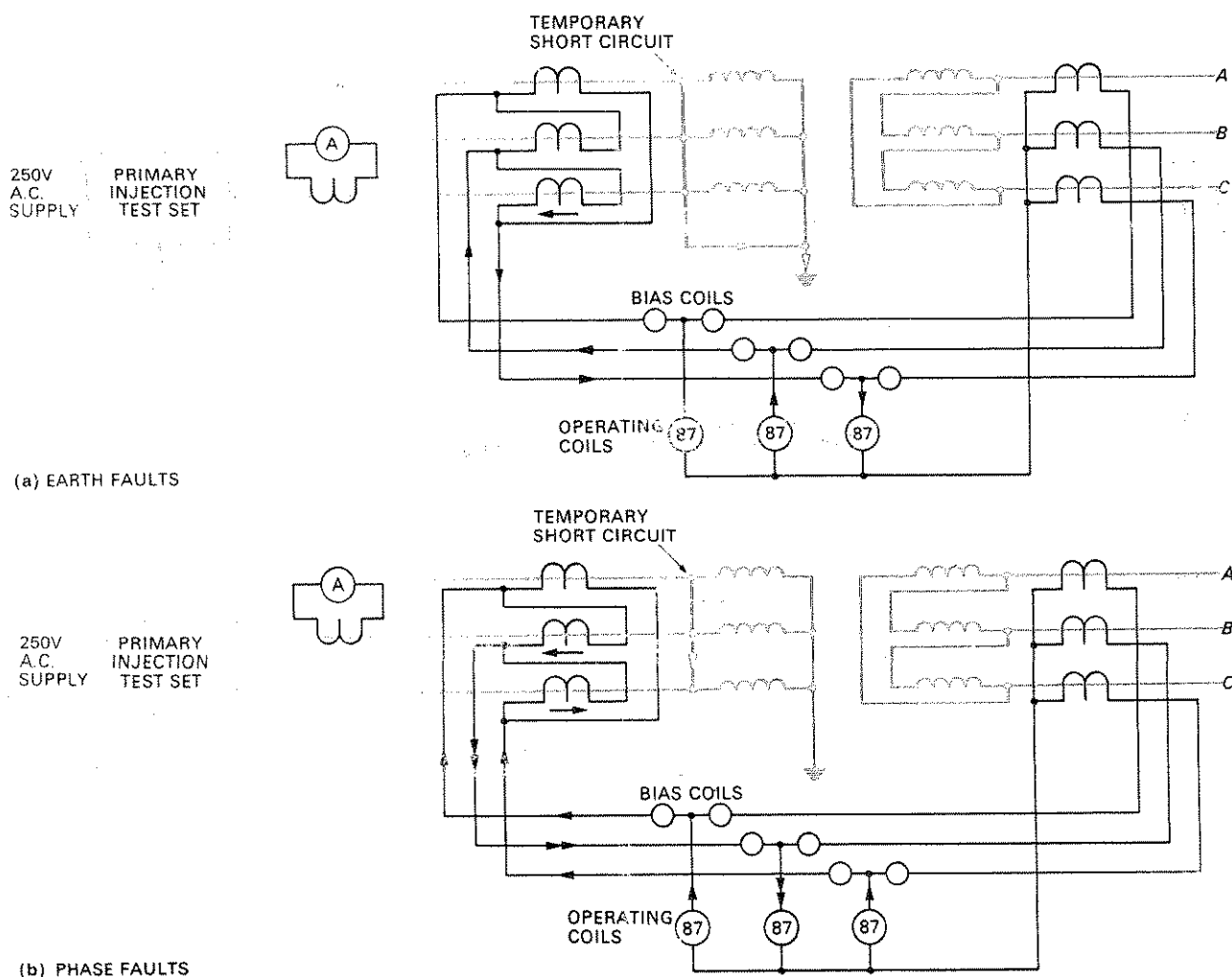


Figure 23.54 Checking sensitivity of transformer differential protection.

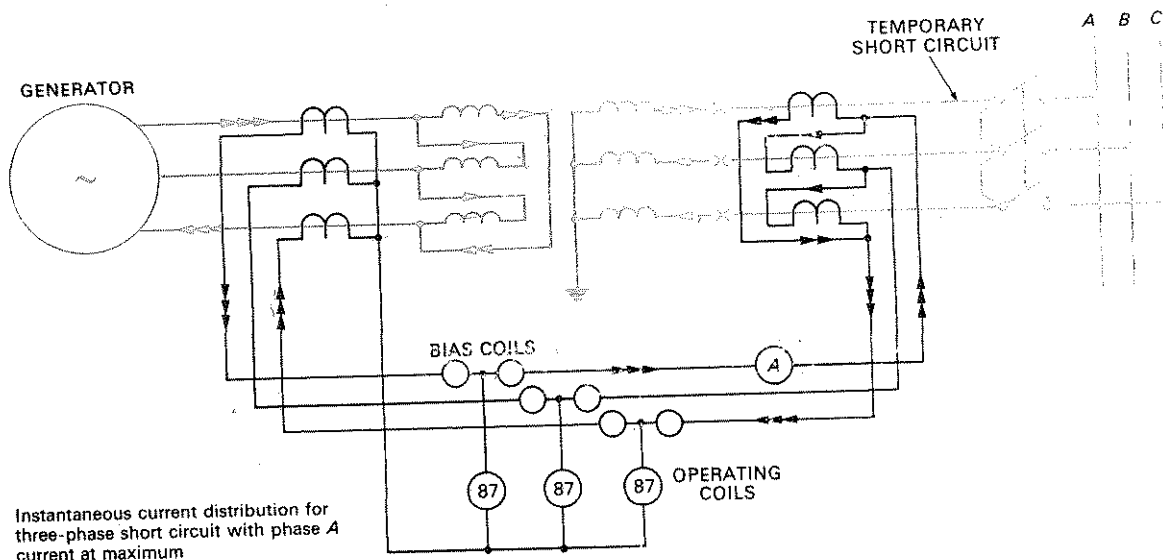


Figure 23.55 Stability check on transformer differential protection.

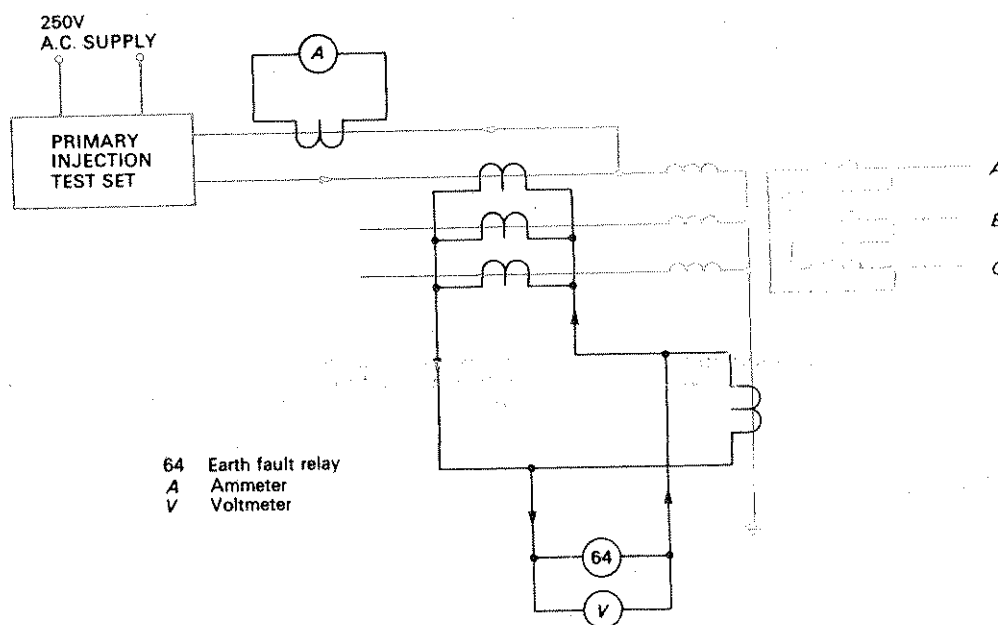


Figure 23.56 Sensitivity check of restricted earth fault protection.

tage required to circulate full load current. If it is not possible to circulate full load current through the transformer, the stability of the protection will have to be checked when the transformer is first put on load.

With the load current flowing through the transformer windings, the protective relay should remain stable and the reading on the ammeters in the relay operating coil circuit should be very small, provided that the main current transformer ratios associated with each transformer winding have been chosen correctly and that the transformer tap changer (if any) is at the nominal tap. It is advisable to measure the spill current through the relay operating coils during the load test with the tap changer set on its maximum or minimum tap. This spill current, expressed as a percentage of the load current used in the test, indicates the minimum amount of bias the relay needs to maintain stability for through faults.

If the relay operates on load with the bias set correctly, the

circuit diagram should be examined to check that the current transformer connections have been made according to the vector group reference of the transformer being protected. Possible errors on the diagram or in the actual secondary wiring are:

- i. The current transformers may have been star-connected on the wrong side.
- ii. A wrong delta connection may have been used on the current transformers.
- iii. The secondary wiring between the groups of current transformers may have been crossed over.

The circuit diagram can best be checked by assuming that there is a three-phase fault on one side of the transformer. The relative instantaneous flow of current in the transformer windings and current transformers can be drawn on the diagram as shown in Figure 23.55 and it can be verified that the current transformer secondary currents circulate



Transformer biased differential protection must also be proved stable in the presence of magnetizing inrush currents to the power transformer. These inrush currents are most severe when the transformer is energized at maximum working voltage with the secondary windings open-circuited. Only the current transformers on the supply side of the protection scheme are energized by the inrush current; this causes current to flow through the relay operating coils. If the relay is of the harmonic restrained type it should remain stable. For other types of relay it may be found necessary either to increase the operating time or to raise the current settings, or both, in order to stabilize the relay against magnetizing current surges.

The stability of the scheme can be checked by injecting through the neutral current transformer and each phase current transformer in turn (Figure 23.57). If the protection is combined with differential protection (Figure 23.58), the connections to the differential relay should be short-circuited in order to circulate the secondary current through the phase current transformer. With full primary load current flowing, the relay should remain stable and the reading on the ammeter connected in series with the relay

This test can be repeated allowing only the *B* phase current transformer to circulate current, and then again for the *C* phase current transformer. If the correct pattern of settings

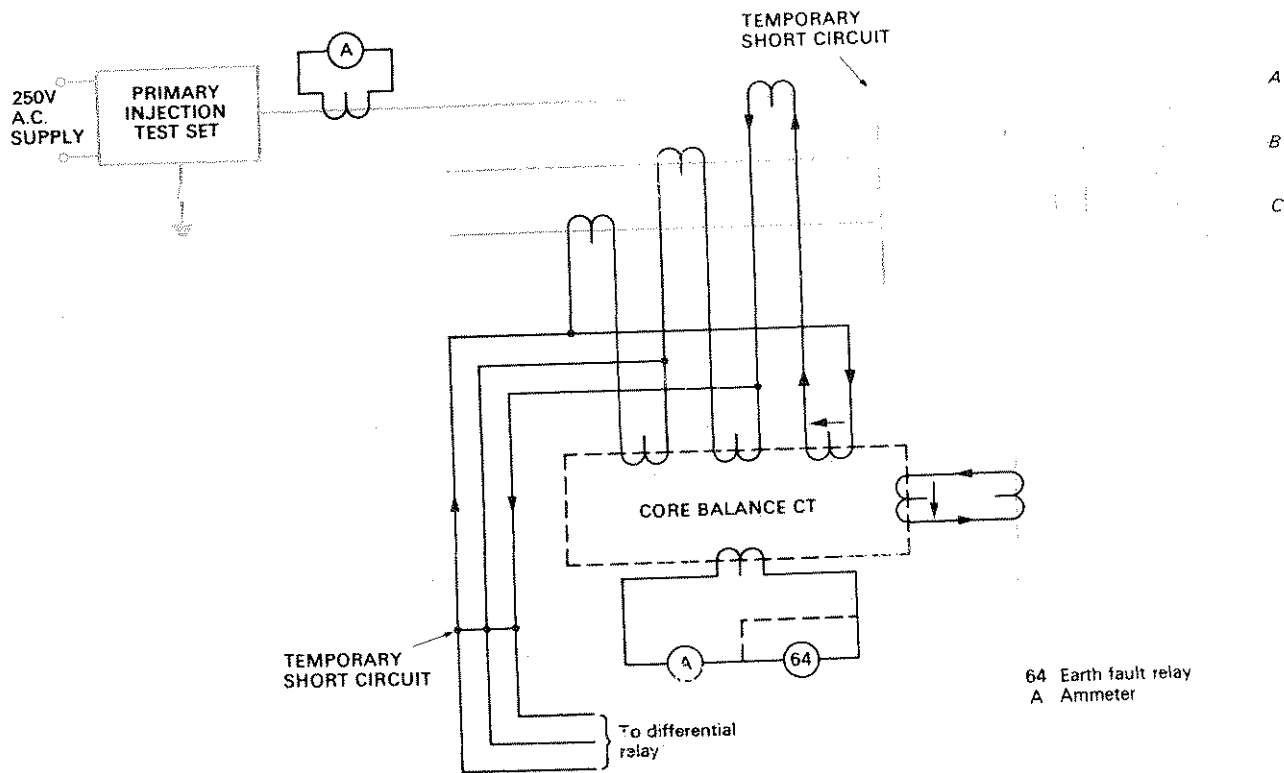


Figure 23.58 Stability test of restricted earth fault protection when combined with differential protection.

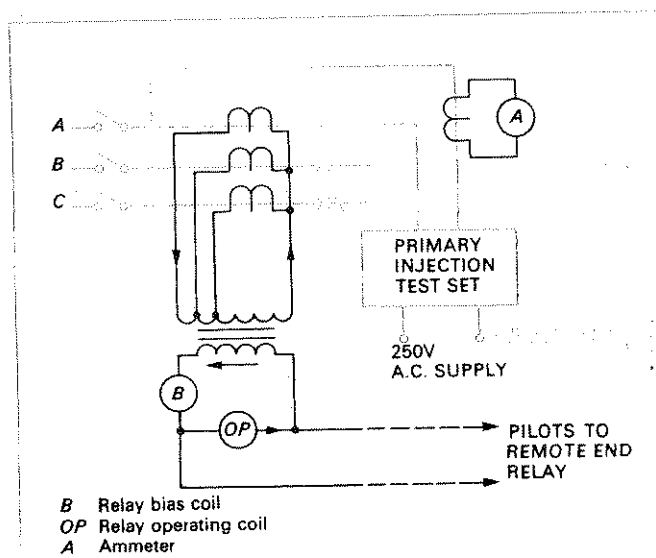


Figure 23.59 Earth fault sensitivity check of pilot wire relay.

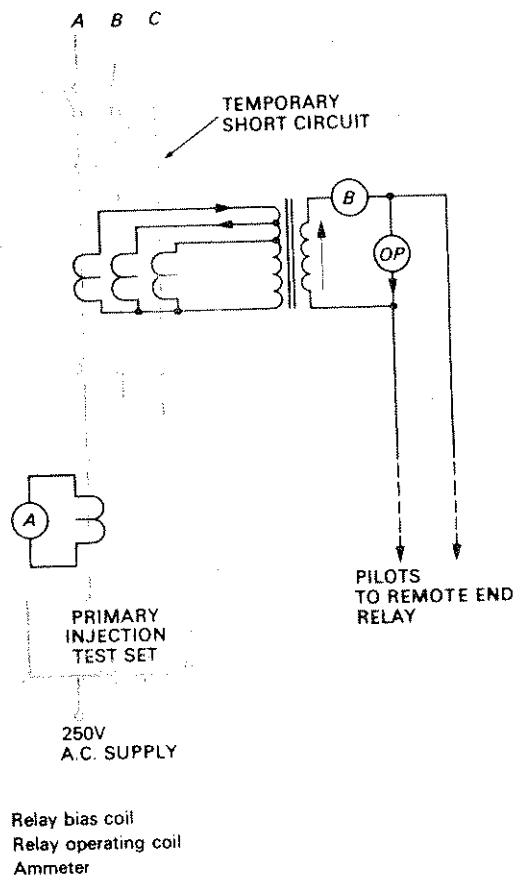
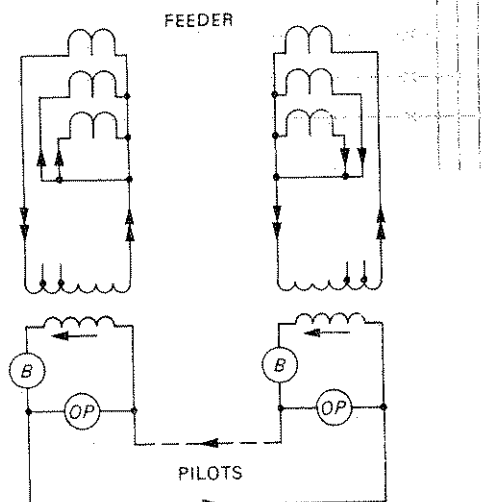


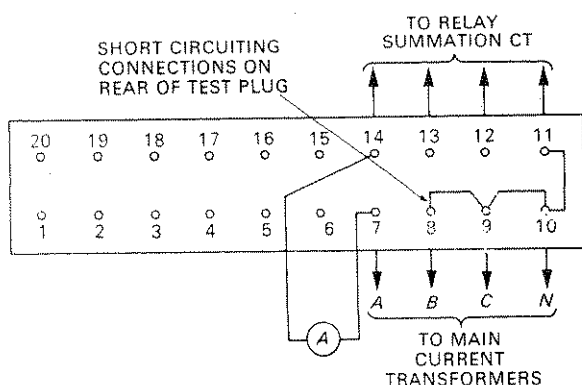
Figure 23.60 Phase fault sensitivity check of pilot wire relay.

A B C



Instantaneous current distribution for three-phase balanced load with phase A current at maximum

(a) LOAD CURRENT DISTRIBUTION



(b) SHORT-CIRCUITING CONNECTIONS ON TEST PLUG FOR LOAD TEST

Figure 23.61 End-to-end stability check of pilot wire protection using load current.

has been recorded when checking the sensitivity of the protection, a comparison between the A phases at either end is all that is necessary to prove stability. The load current used to check the stability should be at least equal to that required to cause relay operation when injecting into the A phase.

### 23.18.7 Busbar protection

Since the current transformers are connected to form a circulating current scheme it is usual that they have the same ratio and be connected with the correct relative polarity. The most convenient way to check ratio and polarity in a large switchgear installation is to choose one circuit as the standard or reference and, after testing its current transformers, use it to check the remaining circuits.

To check that the current transformers of the reference circuit have the same ratio and are in accordance with the ratio marked on their nameplates, primary current should be injected through each current transformer in turn (Figure 23.62). The ratio of the reading on ammeter A1 to that on A2 should approximate closely to the declared current transformer ratio. It is advisable during this test to short-circuit the relay operating coils and stabilizing resis-

tors, as they are not continuously rated to withstand the injected current. A very convenient way of doing this on modern busbar schemes is to operate the supervision relay by hand which in turn operates the hand reset relay for short-circuiting the bus wires. The ammeter should then be transferred to the test link short-circuiting position and the test repeated to verify that the link will short-circuit the current transformer.

To check the polarity of the reference circuit current transformers, current injection should be carried out through the primaries of two current transformers in the group, as shown in Figure 23.63. The bus wires should again be short-circuited for this test to protect the relay coils against possible overheating. Correct polarity is indicated if the reading on the ammeter in the neutral test link is only a few milliamperes. This test should be carried out with first the A and B phases and then the B and C phases. If the scheme is of the duplicate busbar type, in which the current transformers are switched between main and reserve bus wires by isolator auxiliary switches, it is recommended that the tests be carried out with the busbar isolators in both positions in order to check all the wiring.

Having checked the reference circuit current transformers for ratio and polarity, it remains only to check the current transformers of each other circuit against the reference. This is carried out by short-circuiting the zone bus wires, as before, and injecting primary current through the reference circuit current transformers and the current transformers of each of the remaining circuits in turn, as shown in Figure 23.64. The primary current is injected into one pair of phases of the reference circuit, with a three-phase temporary short circuit applied on the test circuit. The ammeters A1 connected at the test links provide the ratio check, while ammeters A2 check the polarity.

The currents measured by ammeters A1 should be the same, but the currents measured by ammeters A2 should be only a few milliamperes if polarity is correct. To verify the ratio and polarity of all the transformers in the test circuit, primary injection should be carried out between A and B and then between B and C phases.

When the ratio and polarity of the current transformers in the test circuit have been proved correct, the ammeters A1 should be transferred to the test link short-circuiting position to verify that the link will short-circuit the current transformers. If the scheme is of the duplicate busbar type, this test should also be carried out with the busbar isolators in both positions to check all the wiring. The sensitivity of the busbar protection should be checked by passing single-phase primary current through one current transformer only and measuring the current necessary to cause operation of the circulating current relay 87 with the maximum number of current transformers in idle shunt. If the scheme is provided with an overall 'check' feature and supervision relay, the sensitivity of these can be checked in the same manner and at the same time.

It should be appreciated that the supervision relay 95 has a very low setting and is arranged to operate the bus wire shorting relay 95X. It is therefore necessary to render this feature inoperative while checking the sensitivity of the circulating current relays 87.

To check that the correct value of stabilizing resistor is used in series with the relays 87, a voltmeter should be connected across the relay coil and stabilizing resistor (Figure 23.65). The voltmeter reading should be noted as the relay operates and this value should agree closely with that predicted by the supplier.

The sensitivity test should be carried out for each discriminating zone and for the overall 'check' feature. The effective minimum primary currents that cause relay operation should approximate closely to those forecast by the supplier of the protection scheme.

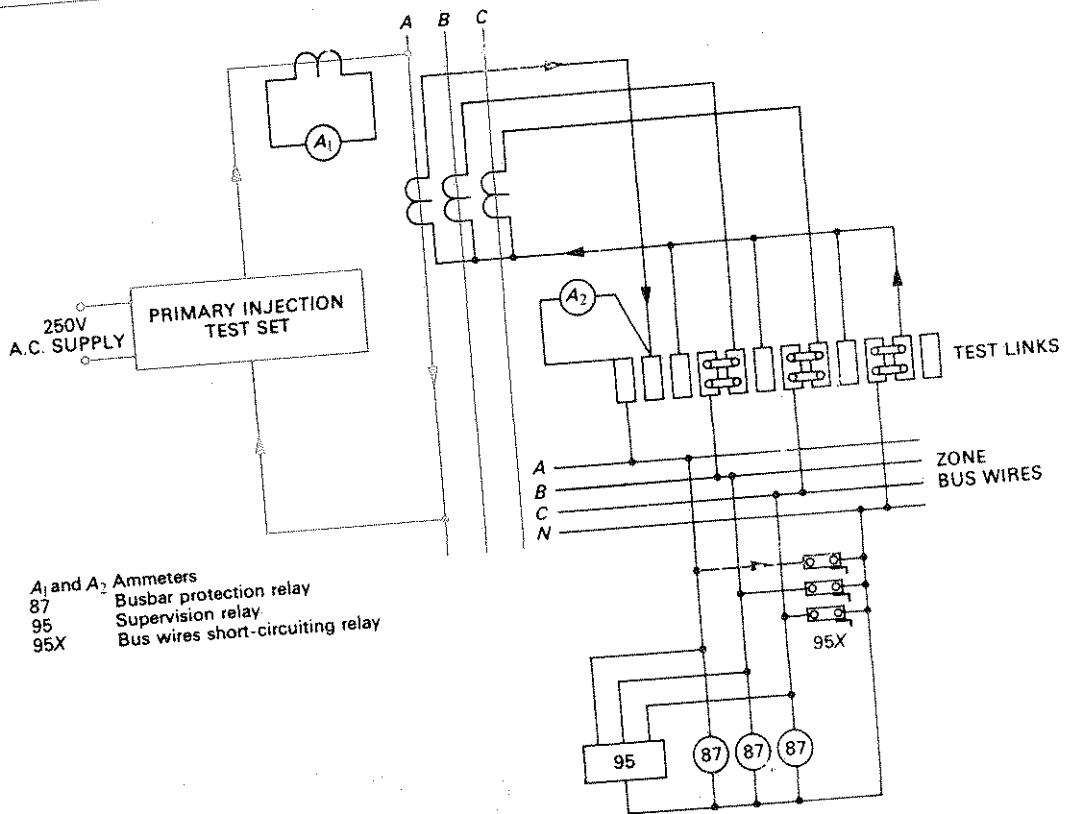


Figure 23.62 Ratio check of current transformers of reference circuit.

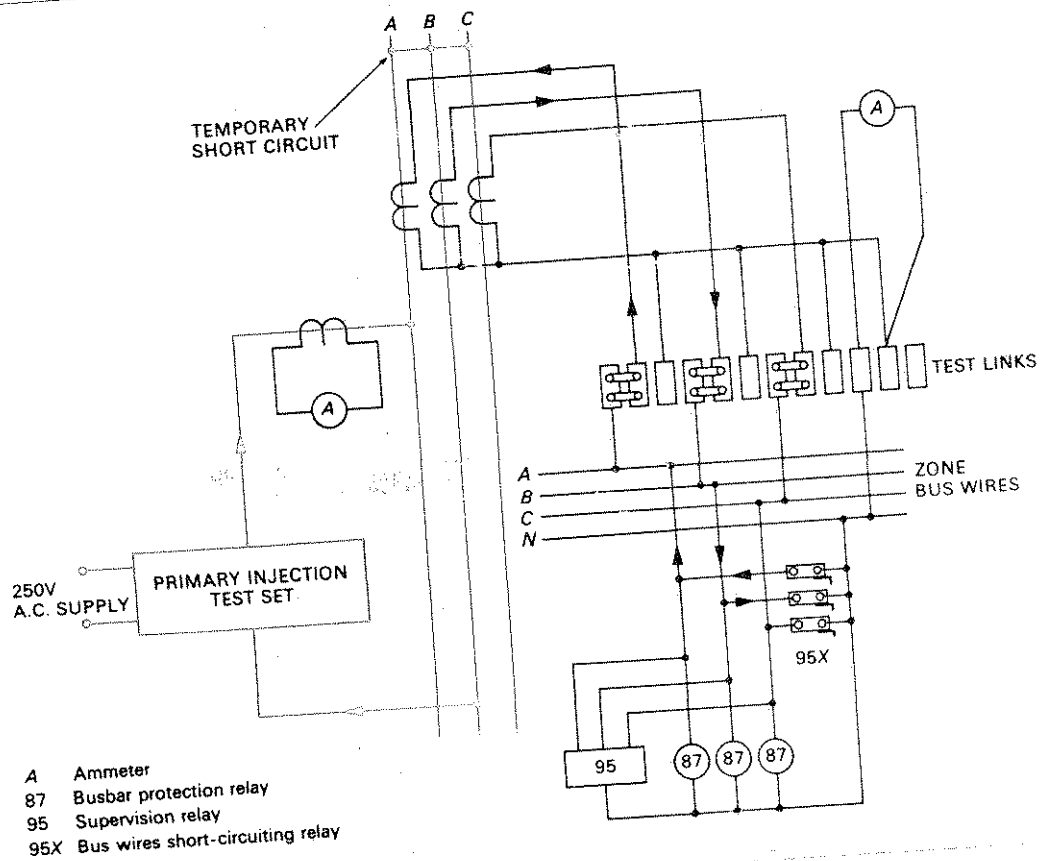


Figure 23.63 Polarity check of reference circuit current transformers.

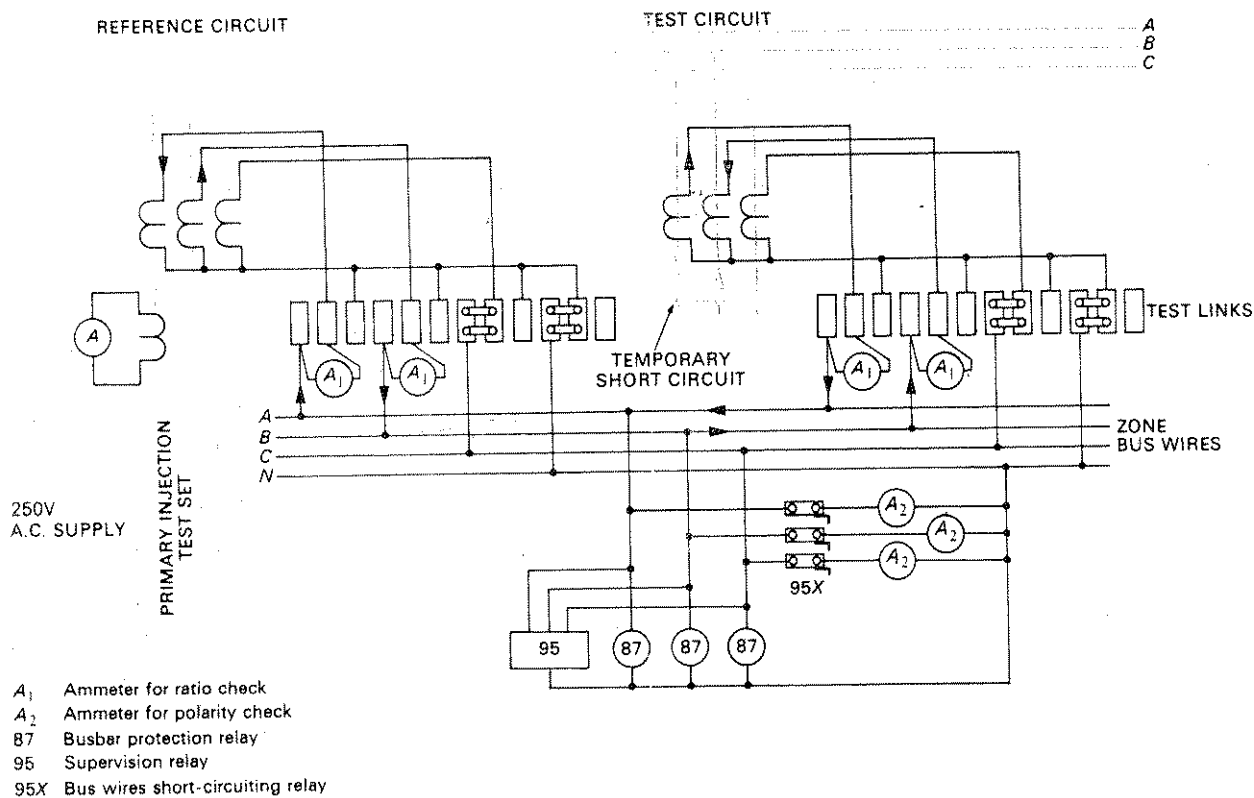


Figure 23.64 Inter-group ratio and polarity check of current transformers in busbar protection scheme.

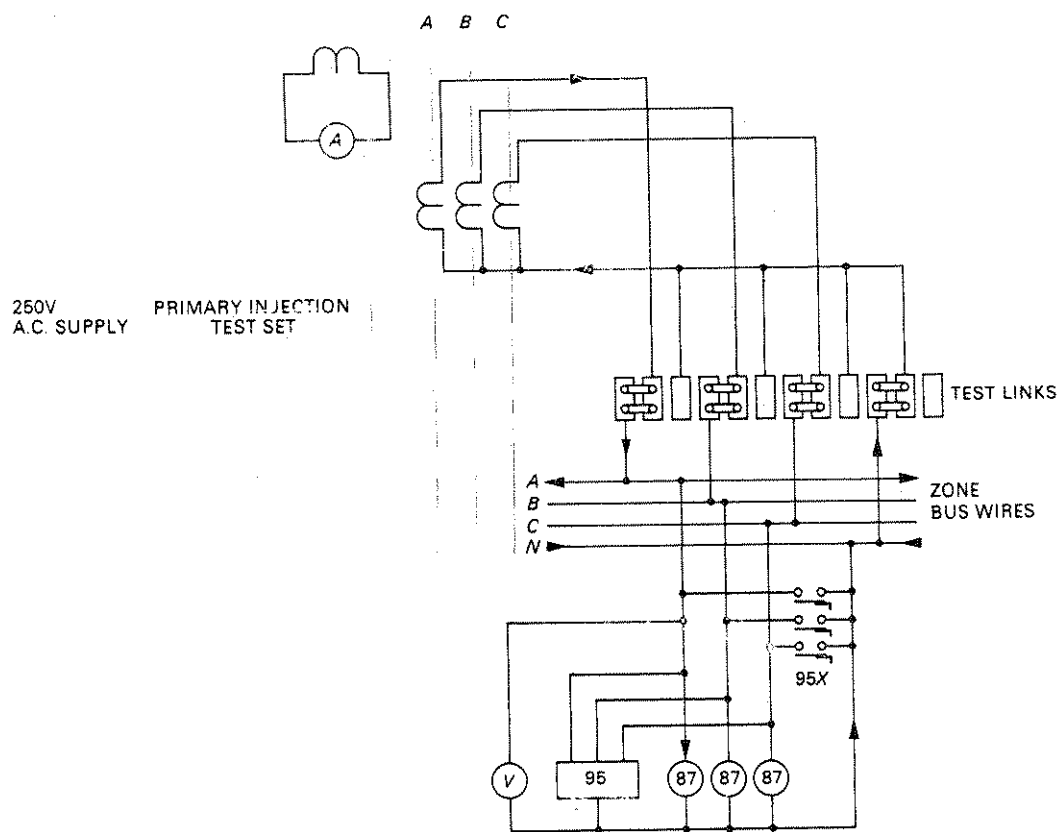


Figure 23.65 Sensitivity check of busbar protection scheme.

### 23.18.8

#### Negative phase sequence relays

The sensitivity of these relays can be checked by using the primary injection test set as shown in Figure 23.66, injecting through each pair of phases in turn. It should be appreciated that these relays are calibrated in negative phase sequence current only, and that, since the injection is simulating a phase to phase fault, only  $1/\sqrt{3}$  of the injected current is negative phase sequence current.

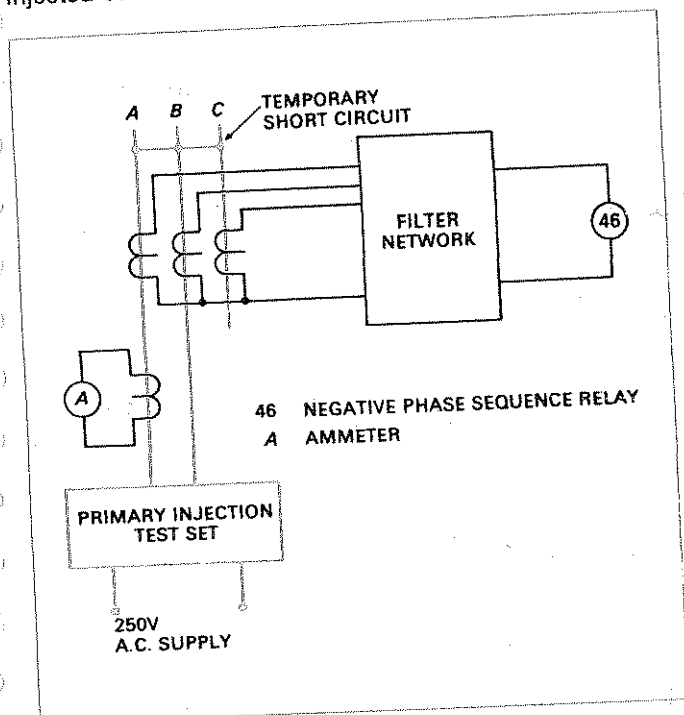


Figure 23.66 Sensitivity check of negative phase sequence relay.

A further check can be made when the circuit is first put on load. If the load is balanced and the phase rotation of the currents supplied to the relay is correct, the relay should not operate. To prove that the relay will operate for negative phase sequence currents, two of the main current transformer secondary phase inputs to the relay should be reversed. This can be done easily by using a test plug inserted into the relay or test block (Figure 23.67). The actual reversal is made on the test plug and it is not necessary to interfere with any wiring. In this test all the phase current entering the relay is negative phase sequence current, and if the relay setting is below the load current value the relay will operate.

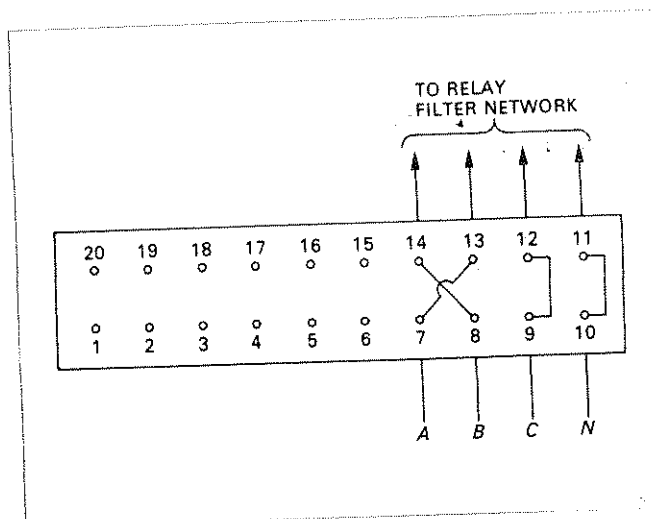


Figure 23.67 Test plug link connections for load current test.

### 23.19

During the primary and secondary injection tests, the trip and alarm circuits are usually rendered inoperative by the removal of isolating links, relay trip latches and so on. It is therefore essential that, when the primary and secondary injection tests have been completed, the tripping and alarm circuits be checked.

This is done by closing the protective relay contacts by hand and checking that the correct circuit breakers are tripped, that the alarm circuits are energized, that the correct flag indications are given and that there is no maloperation of other apparatus that may be connected to the same master trip relay or circuit breaker.

### 23.20

#### 23.20.1

##### Protective gear performance

Statistics show that the overall protective gear performance figure for modern power systems is about 95% or better. The clearance of a fault on the system is correct only if the number of circuit breakers opened is the minimum necessary to remove the fault. A small number of faults are incorrectly cleared, the main reasons being:

- Limitations in protection design.
- Faulty relays.
- Defects in the secondary wiring.
- Incorrect connections.
- Incorrect settings.
- Known application shortcomings accepted as improbable.
- On rare occasions, faulty pilot wires, because of previous damage to a pilot cable of which the maintenance staff was unaware.
- Various other causes, such as switching errors, testing errors, and the operation of relays from mechanical shock.

#### 23.20.2

##### Frequency of inspection and testing

Although protective gear may be in sound condition when first put into service, many troubles can develop unchecked and unrevealed because of its infrequent operation. It is therefore advisable to inspect and test the protective gear at regular intervals, say every 6—12 months. In practice, the frequency of testing may be limited by lack of staff or by the operating conditions on the power system.

Maintenance tests may sometimes have to be made when the protected circuit is on load. The particular equipment to be tested should be taken out of commission and adequate back-up protection provided for the duration of the tests. Such back-up protection may not be fully discriminative, but it is sufficient for it to be capable of clearing any fault on the apparatus whose main protection is temporarily out of service.

It is desirable to carry out maintenance on protective gear at times when the associated power apparatus is out of service. This is facilitated by good co-operation between plant maintenance staff and the protection testing personnel.

#### 23.20.3

##### Maintenance tests

Once primary injection tests have been carried out during the initial commissioning, they need not be made again unless some maloperation has occurred and the protective gear is suspect.

Secondary injection tests should be carried out to check

the relay performance, and, if possible, the relay should be allowed to trip the circuit breakers.

Injection is only necessary on the selected relay setting; the results should be checked against those obtained during the initial commissioning of the gear.

It is better not to interfere with relay contacts at all unless they are obviously corroded. The performance of the contacts is fully checked when the relay is operated electrically with the correct working torques applied to it.

Insulation tests should also be carried out on the relay wiring to earth and between circuits, using a 1000 volt tester. These tests are necessary to detect any deterioration in the insulation resistance.

### 23.21

If the following principles are adhered to as far as possible, the danger of back-feeds is lessened and fault investigation is made easier:

- i. A drawout type of case should be employed, enabling a test plug to be used, and a defective unit to be replaced quickly without interrupting service.
- ii. Circuits should be kept as electrically separate as possible, and the use of common wires should be avoided except where these are essential to the correct functioning of the circuits.
- iii. Each group of circuits which is electrically separate from other circuits should be earthed through an independent earth link.
- iv. Where a common voltage transformer or d.c. supply is used for feeding several circuits, each circuit should be fed through separate links or fuses. When these are withdrawn, the circuits should be completely isolated.
- v. Fuses should, where possible, be graded so that a fault on a circuit not used for protection does not interrupt supplies to the protective gear circuits.
- vi. A single auxiliary switch should not be used for interrupting or closing more than one circuit.
- vii. In relay panel construction, consideration should be given to the accessibility of connections, as these may have to be altered when extensions are made to the gear. Modern panels are provided with special test facilities, so that no connections need be disturbed during routine testing.
- viii. Junction boxes should be of adequate size and, if outdoors, must be made waterproof.
- ix. All wiring should be ferruled for identification and phase-coloured.
- x. In relay design itself, electromagnetic relays should have high operating and restraint torques and high contact pressures; jewel bearings should be shrouded to exclude dust and the use of very thin wire for coils and connections should be avoided. Dust-tight cases with an efficient breather are essential on these types of electromechanical element.

In the more complex modern transistorized protective schemes supplied in the modular type case shown in Figure 23.68, monitor points on the front of the equipment are essential for checking the various stages of the electronic circuits. This facilitates the rapid isolation of any faulty relay module, so that it may be replaced quickly, and the equipment restored to normal service in the minimum of time. Explicit instructions concerning the various voltages, waveforms and so on at the input and output stages of each module are naturally also essential.

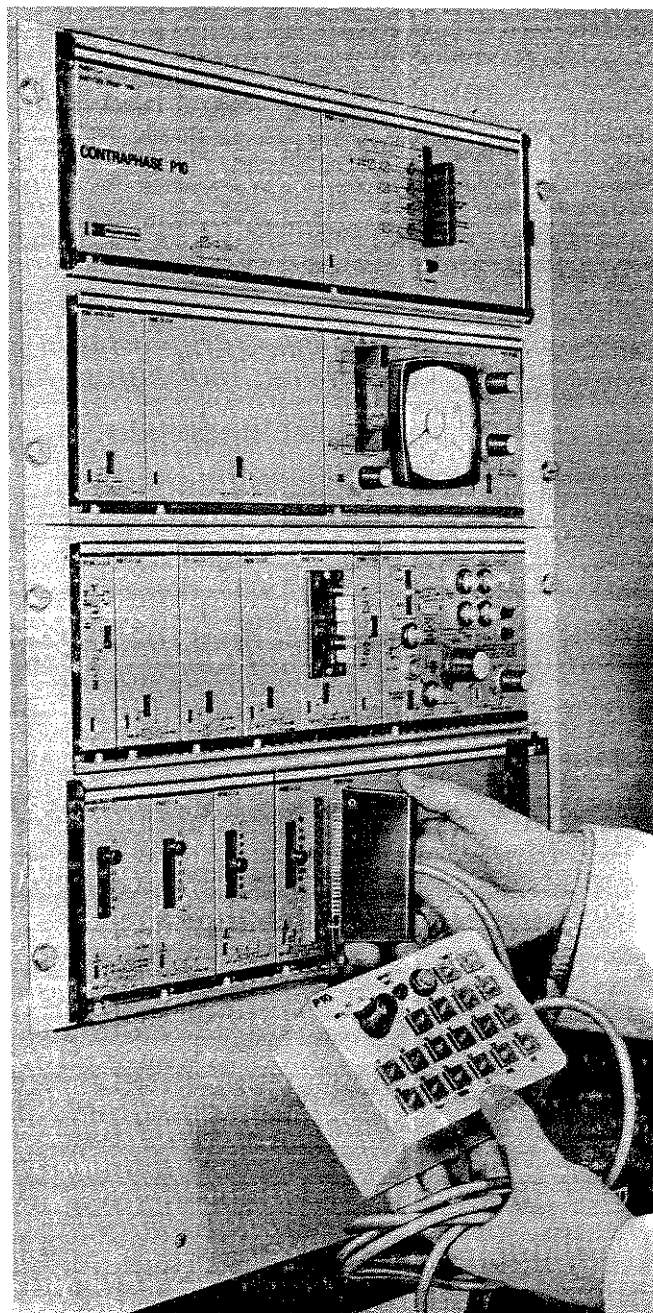


Figure 23.68 Modular case monitor points.

# Relay application tables

- 24.1 Introduction
- 24.2 Application of protective systems
- 24.3 Busbar protection
- 24.4 Generator protection
- 24.5 Generator-transformer protection
- 24.6 Power transformer protection
- 24.7 Auto-transformer protection
- 24.8 Unit transformer protection
- 24.9 Earthing transformer protection
- 24.10 Protection of transmission lines and feeders
- 24.11 Transformer-feeder protection
- 24.12 Reactor protection
- 24.13 Induction motor protection
- 24.14 Protection of synchronous motors and compensators (synchronous condensers)
- 24.15 Rectifier protection
- 24.16 Auto-reclosing equipment
- 24.17 Summary of individual relays

## 24.1

### INTRODUCTION

This chapter deals with the various factors to be considered in the application of protective systems to different kinds of electrical plant, and gives general recommendations as to the type of equipment to be used.

In case of doubt concerning the most suitable protection in any particular case, reference should be made to GEC ALSTHOM Measurements, Stafford.

## 24.2

### APPLICATION OF PROTECTIVE SYSTEMS

There are usually several ways of protecting any given equipment, some of which are complementary to one another. The following tables offer examples of protective schemes affording adequate protection to different kinds of electrical plant and associated equipment. The table references for the various types of plant are indicated in Figure 24.1. If alternative schemes embodying one or more protective systems are available, help in selecting the most appropriate may be obtained from the relevant notes, references to the main text, and the main considerations outlined in Figure 24.2.

It is not practicable to cover every form of protective system, or every application; in the tables the systems which are parts of each scheme are classified as follows:

- O General application.
- X To be applied if the special nature of the plant requires it.
- Y To be applied if system conditions permit.

Current transformer requirements are not specified, as this consideration is governed by the individual type of system as well as many other factors; the supplier of the equipment should be consulted.

### 24.2.1

#### Relay systems

The relays required to complete each protective system are shown in the relevant table; these may be taken as indicative of the best practice. For many systems, only the most important unit has been given. Auxiliary relays and other items required cannot, in many cases, be specified without making the tables excessively long and complex; a summary of the individual relays is given in Section 24.17.



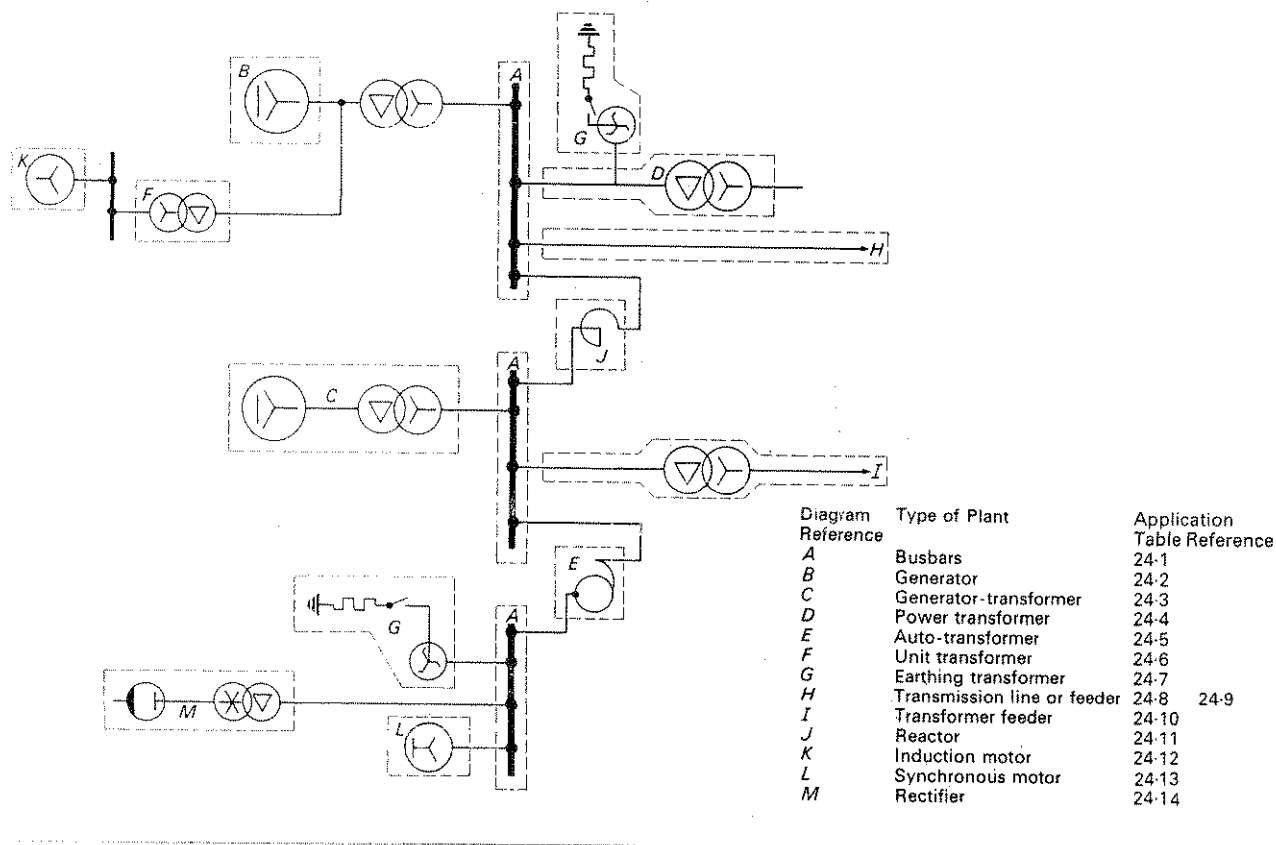


Figure 24.1 Zones of protection.

One relay can often be used for several functions; for example, a triple pole overcurrent relay can be used for both phase and earth fault protection. In such cases the relay type has been given for all functions separately, and care should be exercised in specifying the actual number of relays or elements required.

The following combinations are commonly found in practice:

- Inverse time overcurrent protection for phase and earth faults.
- Inverse time with instantaneous high set overcurrent phase fault protection with or without inverse time earth fault protection.
- Thermal overcurrent, with instantaneous overcurrent protection for phase and earth faults.

## 24.2.2

### Power system neutral

Throughout this chapter, the system neutral is considered to be earthed when the neutral point is connected to earth either directly or through a resistance. EHV systems are usually earthed directly at every transforming point. Systems at voltages up to 33 kV are frequently earthed through a resistance, although there is a growing tendency to apply solid earthing at such voltages as well.

Earth fault protection is applicable in all such cases; the prospective earth fault current must be considered when an earth fault setting is chosen.

The neutral point is considered to be insulated when the neutral point is not connected to earth or is connected to earth through a continuously rated arc suppression coil or through a voltage transformer.

Arc suppression coils are a form of protection applicable to power systems for which the majority of earth faults are expected to be of a transient nature only. Their application depends on the locality through which overhead lines pass, the insulation level of the system equipment, and the incidence of flash-over type earth faults.

Arc suppression coils can be continuously rated or short time rated (usually 30 seconds) with one phase of the system faulted to earth.

The short time rated coil is short-circuited either directly or through a resistance after operating for a short time, so that a persistent earth fault can be cleared by normal discriminative earth fault protection.

Continuously rated coils can be provided with an alarm to indicate the presence of a persistent fault; in some cases directional earth fault relays are used to indicate the location of an earth fault.

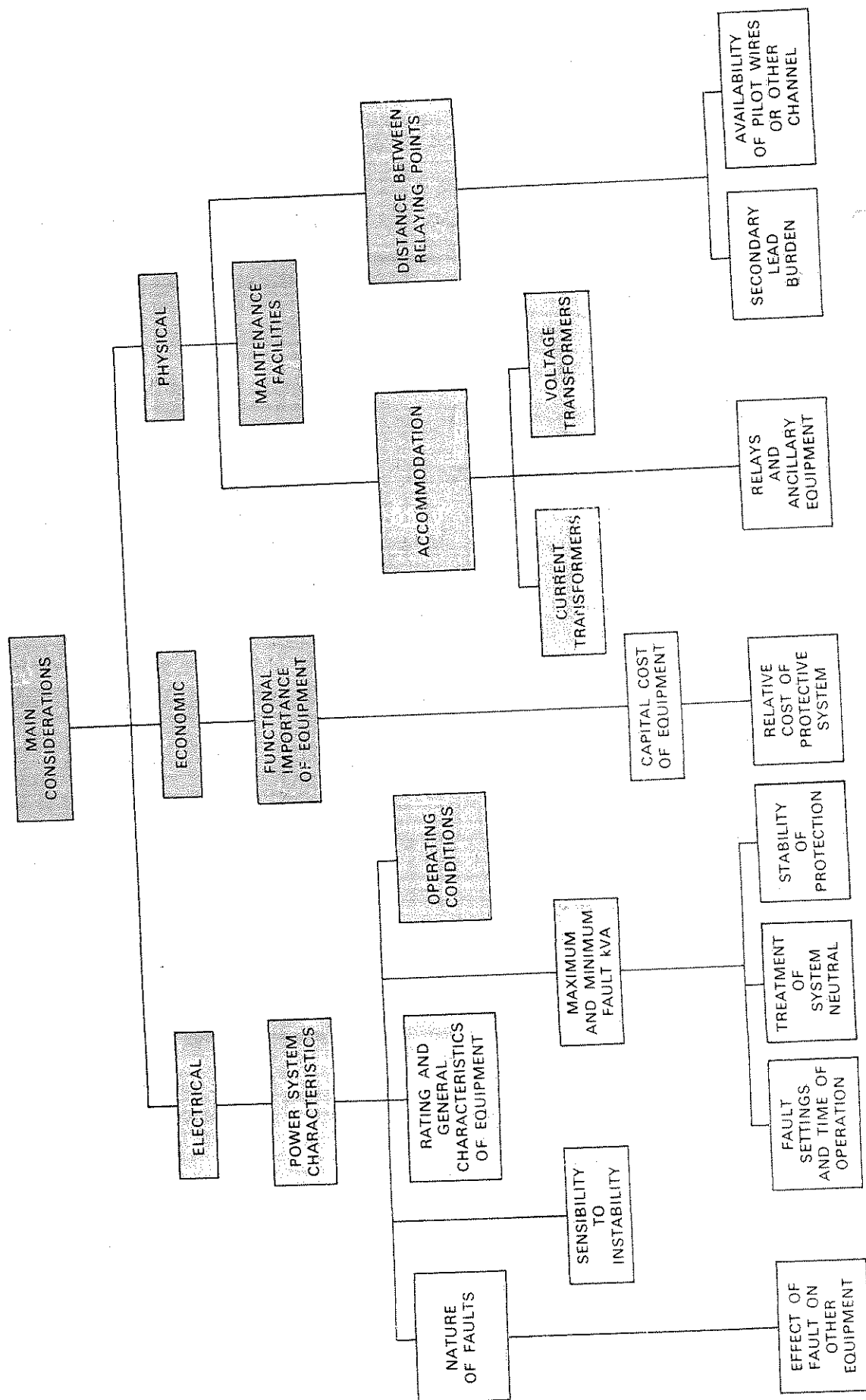


Figure 24.2 Protective system selection.

## 24.3

The recommendations in Table 24.1 cover busbars; they are grouped in terms of 'main' and 'check' systems for switchgear ratings of 350 MVA and below and for ratings over 350 MVA, and for earthed neutral and insulated neutral power systems.

The switchgear and its associated connections are usually included in the zone of protection.

Unrestricted systems of protection (distance, overcurrent and earth fault systems) provide a measure of busbar protection, although it is not possible to give instantaneous protection, since discrimination must be maintained between sections of feeder protection.

All protection schemes specifically for busbars should preferably comprise two independent protective systems, usually designated 'main' and 'check', the combinations of which are shown in the table. With this arrangement, tripping must not take place until both the main and the check systems have operated.

Check systems do not usually discriminate between main and reserve bars or between sections of them.

When by-pass isolators are used, special provision must be made for operation under by-pass conditions.

| Protective system |                   | Section reference | Power system neutral |               |   |   |           |                   |               | Relay type     |                          |
|-------------------|-------------------|-------------------|----------------------|---------------|---|---|-----------|-------------------|---------------|----------------|--------------------------|
|                   |                   |                   | Earthed              |               |   |   | Insulated |                   |               | Drawout relay  | MIDOS relay              |
|                   |                   |                   | 350 MVA and below    | Above 350 MVA |   |   |           | 350 MVA and below | Above 350 MVA |                |                          |
|                   |                   |                   |                      | Schemes       |   |   |           |                   |               |                |                          |
| Main              | Check             |                   |                      | 1             | 2 | 3 | 4         |                   |               |                |                          |
| Frame-earth fault | —                 | 15.5.1            | Y                    | O             | — | — | —         | —                 | —             | CAG12          | MCAG12                   |
|                   |                   | 15.5.2            |                      |               |   |   |           |                   |               |                |                          |
|                   |                   | 15.5.3            |                      |               |   |   |           |                   |               |                |                          |
| Differential      | —                 | 15.8.1            | —                    | —             | O | O | O         | —                 | O             | FAC34<br>CAG34 | MFAC34<br>MCAG34<br>MBCZ |
|                   |                   | 15.10.1           |                      |               |   |   |           |                   |               |                |                          |
| —                 | Frame-earth fault | 15.5.1            | —                    | —             | O | — | —         | —                 | —             | CAG12          | MCAG12                   |
|                   |                   | 15.5.2            |                      |               |   |   |           |                   |               |                |                          |
|                   |                   | 15.5.3            |                      |               |   |   |           |                   |               |                |                          |
| —                 | Differential      | 15.8.1            | —                    | —             | — | O | —         | —                 | O             | FAC34<br>CAG34 | MFAC34<br>MCAG34<br>MBCZ |
|                   |                   | 15.10.1           |                      |               |   |   |           |                   |               |                |                          |
| —                 | Neutral check     | 15.5.4            | Y                    | O             | — | — | O         | —                 | —             | CAG12          | MCAG12                   |

O

 General applications

Y

 Where applicable

O General applications  
Y Where applicable

Table 24.1 Busbar protection

## 24.4 GENERATOR PROTECTION

The recommendations in Table 24.2 cover the protection of generators rated above 1 MVA. For machines of lower ratings, guidance may be obtained from the table, but consideration must be given to the cost and functional importance of the plant.

Reverse power protection should always be applied to engine-driven generators operated in parallel with others or synchronized with a power system.

It is usual to fit thermal devices to monitor the temperature on all machines rated above 5 MVA.

Protective systems intended to cover internal faults should completely isolate the generator by closing the power drive stop valve, tripping the main a.c. circuit breaker and removing the field excitation.

| Protective System                       | Section Reference | Steam and gas turbine driven |   |             | Water turbine driven |   |             | Diesel engine driven | Relay type              |                            |
|-----------------------------------------|-------------------|------------------------------|---|-------------|----------------------|---|-------------|----------------------|-------------------------|----------------------------|
|                                         |                   | 1-5 MVA                      |   | Above 5 MVA | 1-5 MVA              |   | Above 5 MVA |                      | Drawout relay           | MIDOS relay                |
|                                         |                   | Schemes                      |   |             | Schemes              |   |             |                      |                         |                            |
|                                         |                   | 1                            | 2 |             | 1                    | 2 |             |                      |                         |                            |
| Differential                            | 17.5.1<br>17.6.1  | O                            | - | O           | O                    | - | O           | -                    | CAG34<br>FAC34<br>DDG31 | MCAG34<br>MFAC34<br>-      |
| Restricted earth fault                  | 17.5.1            | -                            | O | -           | -                    | O | -           | O                    | FAC14<br>CAG14          | MFAC14<br>MCAG14           |
| Overcurrent                             | 17.8              | X                            | O | O           | X                    | O | O           | O                    | CDG31<br>CDV61<br>CDV62 | MCGG62<br>MCGV             |
| Phase unbalance                         | 17.11             | X                            | X | O           | -                    | - | -           | -                    | CTN                     | MCND                       |
| Rotor earth fault                       | 17.12.1           | -                            | - | O           | -                    | - | O           | -                    | VME<br>DBAE4            | MRSU                       |
| Reverse power                           | 17.15.1           | X                            | X | X           | X                    | X | -           | O                    | WCG<br>WDG<br>WCD11     | MWTU                       |
| Under power and reverse power interlock | 17.15.2           | -                            | - | X           | -                    | - | -           | -                    | WCD12                   | -                          |
| Overvoltage                             | 17.10             | -                            | - | -           | O                    | O | O           | -                    | VDG11<br>VAG11          | MVTD12<br>MVTI12           |
| Field failure undercurrent              | 17.13             | X                            | X | -           | X                    | X | -           | X                    | DBA4                    | -                          |
| Field failure impedance                 | 17.13.1           | -                            | - | O           | -                    | - | O           | -                    | YCGF                    | MYTU                       |
| Pole slipping                           | 17.13.2           | -                            | - | X           | -                    | - | X           | -                    | ZTO11                   | -                          |
| Rotor temperature                       | 17.7              | -                            | - | O           | -                    | - | O           | -                    | -                       | -                          |
| Stator earth fault                      | 17.9              | O                            | O | O           | O                    | O | O           | O                    | CDG11<br>VDG14<br>VMU31 | MCGG22<br>MVTD13<br>MVTU13 |

O

 General applications

X

 Where required

Table 24.2 Generator protection

## 24.5

The recommendations in Table 24.3 cover generator-transformer units rated above 5 MVA. Similar practice can be applied to any smaller units with discretion.

The ratings of transformers to which thermal devices are applicable are specified in BS 171.

Protective systems intended to cover internal faults should effect complete isolation of the unit.

In generator-transformer units the relative location of the generator, transformer and high voltage switchgear may result in the secondary lead burdens being large; for this reason, the application of balanced protective systems may require special consideration.

| Protective system                          | Section reference | Transformer high voltage neutral |                      |                            |                      | Relay type                                |                       |
|--------------------------------------------|-------------------|----------------------------------|----------------------|----------------------------|----------------------|-------------------------------------------|-----------------------|
|                                            |                   | Earthed                          |                      | Insulated                  |                      | Drawout relay                             | MIDOS relay           |
|                                            |                   | Generator neutral earthing       |                      | Generator neutral earthing |                      |                                           |                       |
|                                            |                   | Resistance                       | Earthing transformer | Resistance                 | Earthing transformer |                                           |                       |
| Differential                               | 17.5.2            | O                                | O                    | O                          | O                    | DDGT31<br>DMH31<br>DTH31                  | MBCH                  |
| Transformer HV restricted earth fault      | 16.6              | X                                | X                    | —                          | —                    | FAC14<br>CAG14                            | MFAC14<br>MCAG14      |
| Time delayed overcurrent                   | 17.8              | O                                | O                    | O                          | O                    | CDG31<br>CDV61                            | MCGG62                |
| Lower voltage instantaneous earth fault    | 17.2              | O                                | —                    | O                          | —                    | CAG14                                     | MCAG14                |
|                                            | 17.9              | O                                | —                    | O                          | —                    | CAG14                                     | MCAG14                |
| Lower voltage time delayed earth fault     | 17.2              | X                                | —                    | X                          | —                    | CDG11                                     | MCGG22                |
|                                            | 17.9              | —                                | O                    | —                          | O                    | CDG11 + harmonic filter<br>VDG14<br>VMU31 | —<br>MVTU13<br>MVTU13 |
| Phase unbalance                            | 17.11             | X                                | X                    | X                          | X                    | CTN                                       | MCND                  |
| Overvoltage                                | 17.10             | X                                | X                    | X                          | X                    | VDG11<br>VAG11                            | MVTD12<br>MVTI12      |
| Field failure undercurrent                 | 17.13             | X                                | X                    | X                          | X                    | DBA4                                      | —                     |
| Field failure impedance                    | 17.13.1           | X                                | X                    | X                          | X                    | YCGF                                      | MYTU                  |
| Pole slipping                              | 17.13.2           | X                                | X                    | X                          | X                    | ZTO11                                     | —                     |
| Rotor earth fault                          | 17.12.1           | O                                | O                    | O                          | O                    | VME<br>DBAE4                              | MRSU                  |
| Reverse power                              | 17.15.1           | X                                | X                    | X                          | X                    | WDG<br>WCG<br>WCD11                       | MWTU                  |
| Under power and reverse power interlocking | 17.15.2           | X                                | X                    | X                          | X                    | WCD12                                     | —                     |
| Overfluxing                                | 16.2.8<br>16.11   | O                                | O                    | O                          | O                    | GTT                                       | —                     |
| Winding temperature                        | 17.7<br>16.4      | O                                | O                    | O                          | —                    | TTT                                       | —                     |
| Buchholz                                   | 16.3              | O                                | O                    | O                          | O                    | —                                         | —                     |

O General applications

X Where required

O General applications  
X Where required

Table 24.3 Generator-transformer protection

## 24.6

### POWER TRANSFORMER PROTECTION

The recommendations in Table 24.4 cover power transformers but not auto-transformers. The application of the protective systems must be considered with respect to each winding. Unloaded tertiary windings are frequently not separately protected, or are protected only by an earth fault relay energized by a current transformer in a single earthing connection.

Thermal devices are used with the larger transformers, the ratings of the transformers to which they are applicable being specified in BS 171.

For parallel-connected transformers, or for those in which power can flow in either direction, it is essential that protection against internal faults effect complete isolation of the transformer.

| Protective system                    | Section reference | Winding and/or power system neutral earthed |             |   | Winding and/or power system neutral insulated |             | Relay type              |                  |
|--------------------------------------|-------------------|---------------------------------------------|-------------|---|-----------------------------------------------|-------------|-------------------------|------------------|
|                                      |                   | Up to 1 MVA                                 | Above 1 MVA |   | Up to 1 MVA                                   | Above 1 MVA | Drawout relay           | MIDOS Relay      |
|                                      |                   |                                             | Schemes     |   |                                               |             |                         |                  |
|                                      |                   |                                             | 1           | 2 |                                               |             |                         |                  |
| Longitudinal differential            | 16.7              | —                                           | O           | — | —                                             | O           | DDT32<br>DMH31<br>DTH31 | MBCH             |
| Time-delayed overcurrent             | 16.5.2            | O                                           | O           | O | O                                             | O           | CDG31                   | MCGG62           |
| Instantaneous restricted earth fault | 16.6              | O                                           | X           | O | —                                             | —           | CAG14<br>FAC14          | MCAG14<br>MFAC14 |
| Time delayed earth fault             | 16.5.2            | X                                           | X           | X | —                                             | —           | CDG11<br>CDG12          | MCGG22           |
| Overfluxing                          | 16.11             | —                                           | X           | X | —                                             | X           | GTT                     | —                |
| Overheating                          | 16.4              | —                                           | X           | X | —                                             | X           | TTT                     | —                |
| Buchholz                             | 16.13             | X                                           | O           | O | X                                             | O           | —                       | —                |
| O General applications               |                   |                                             |             |   |                                               |             |                         |                  |
| X Where required                     |                   |                                             |             |   |                                               |             |                         |                  |

Table 24.4 Power transformer protection (excluding auto-transformers)

## 24.7

The recommendations in Table 24.5 cover auto-transformers, but not including motor-starting auto-transformers.

It is usual to apply Buchholz protection to all large transformers provided with a conservator; this will generally apply to the auto-transformers considered in this section and such protection is included in the table subject to this provision.

The ratings of auto-transformers to which thermal devices are applicable are specified in BS 171.

If power can flow into any winding, protection intended to cover internal faults must effect complete isolation.

In auto-transformers with more than one winding per phase, overcurrent protection must be applied to each winding.

Scheme 1 provides a simple instantaneous differential system for main windings, but tertiary windings are not included in the operating zone of this protection.

| Protective system                                         | Section reference | Winding and/or power system neutral earthed |   |   | Winding and/or power system neutral insulated |   | Relay type     |                  |
|-----------------------------------------------------------|-------------------|---------------------------------------------|---|---|-----------------------------------------------|---|----------------|------------------|
|                                                           |                   | Schemes                                     |   |   | Schemes                                       |   | Drawout relay  | MIDOS relay      |
|                                                           |                   | 1                                           | 2 | 3 | 1                                             | 2 |                |                  |
| Differential (over main winding only)                     | 16.8              | 0                                           | — | — | 0                                             | — | CAG34<br>FAC34 | MCAG34<br>MFAC34 |
| Differential (over all winding)                           | 16.7              | —                                           | 0 | — | —                                             | 0 | DMH31<br>DTH31 | MBCH             |
| Time delayed overcurrent                                  | 16.5.2            | 0                                           | 0 | 0 | 0                                             | 0 | CDG31          | MCGG62           |
| Instantaneous restricted earth fault                      | 16.8              | —                                           | X | X | —                                             | — | FAC14<br>CAG14 | MFAC14<br>MCAG14 |
| Instantaneous restricted earth fault for tertiary winding | 16.8              | X                                           | — | — | —                                             | — | FAC14<br>CAG14 | MFAC14<br>MCAG14 |
| Time delayed earth fault                                  | 16.5.2            | X                                           | X | X | —                                             | — | CDG11<br>CDG12 | MCGG22           |
| Overheating                                               | 16.4              | 0                                           | 0 | 0 | 0                                             | 0 | TTT            | —                |
| Buchholz                                                  | 16.13             | 0                                           | 0 | 0 | 0                                             | 0 | —              | —                |

0 General Applications  
X Where required

Table 24.5 Auto-transformer protection (excluding motor starting auto-transformers)

## 24.8

### UNIT TRANSFORMER PROTECTION

The recommendations in Table 24.6 cover transformers directly connected to generators for the purpose of supplying power to associated auxiliary equipment.

The application of protective systems must be considered with respect to each winding.

Protective systems intended primarily to cover internal faults should effect complete isolation of the generator and unit transformer.

The rating of transformers to which thermal devices are applicable are specified in BS 171.

When the generator neutral is insulated, generator neutral displacement protection provides earth fault protection for the high voltage winding of the unit transformer.

Low voltage neutral displacement protection, for use with neutral insulated LV systems, can only provide indication that an earth fault condition on the system exists; it cannot be used to trip the faulty circuit.

| Protective system                                 | Section reference | Transformer low voltage neutral |                             |                           |                             |           |   | Relay type              |                  |
|---------------------------------------------------|-------------------|---------------------------------|-----------------------------|---------------------------|-----------------------------|-----------|---|-------------------------|------------------|
|                                                   |                   | Earthed                         |                             |                           |                             | Insulated |   | Drawout relay           | MIDOS relay      |
|                                                   |                   | Generator neutral earthed       | Generator neutral insulated | Generator neutral earthed | Generator neutral insulated | Schemes   |   |                         |                  |
|                                                   |                   |                                 |                             |                           |                             |           |   |                         |                  |
|                                                   |                   |                                 |                             |                           |                             |           |   |                         |                  |
| 1                                                 | 2                 | 1                               | 2                           |                           |                             |           |   |                         |                  |
| Longitudinal differential                         | 17.16.2           | 0                               | —                           | —                         | 0                           | —         | — | DDT32<br>DMH31<br>DTH31 | MBCH             |
| Time delayed overcurrent                          | 16.5.2            | 0                               | 0                           | 0                         | 0                           | 0         | 0 | CDG31                   | MCGG62           |
| High voltage instantaneous restricted earth fault | 16.6<br>17.16.2   | —                               | X                           | —                         | —                           | X         | — | FAC14<br>CAG14          | MFAC14<br>MCAG14 |
| Low voltage instantaneous restricted earth fault  | 16.6              | —                               | 0                           | 0                         | —                           | —         | — | FAC14<br>CAG14          | MFAC14<br>MCAG14 |
| Low voltage neutral displacement                  | 16.15.1           | —                               | —                           | —                         | 0                           | 0         | 0 | VDG12<br>VMU21          | MVTD13<br>MVTU13 |
| Buchholz                                          | 16.13             | X                               | X                           | X                         | X                           | X         | X | —                       | —                |
| 0 General applications<br>X Where required        |                   |                                 |                             |                           |                             |           |   |                         |                  |

Table 24.6 Unit transformer protection



The recommendations in Table 24.7 cover earthing transformers.

The earthing transformer is usually included in the zone of protection of the associated power transformer; composite protection is arranged as described in Section 16.9.3.

When not covered by the main power transformer protection, overcurrent and restricted earth fault protection can be applied as indicated.

It is usual to apply an overcurrent relay with a long time delay to protect the earthing transformer (and resistor if any) against sustained zero sequence current flowing to an uncleared system earth fault. The time delay is then related to the short time thermal rating of the earthing plant.

| Protective system                          | Section reference | Solidly connected to power transformer | Individually connected to power system | Relay type     |                  |
|--------------------------------------------|-------------------|----------------------------------------|----------------------------------------|----------------|------------------|
|                                            |                   |                                        |                                        | Drawout relay  | MIDOS relay      |
| Time delayed zero sequence overcurrent     | —                 | O                                      | O                                      | CDG12          | MCGG22           |
| Time delayed positive sequence overcurrent | 16.10             | —                                      | X                                      | CDG31          | MCGG62           |
| Instantaneous restricted earth fault       | 16.6              | —                                      | X                                      | FAC14<br>CAG14 | MFAC14<br>MCAG14 |
| Buchholz                                   | 16.13             | O                                      | O                                      | —              | —                |

O General applications  
 X Where required

Table 24.7 Earthing transformer protection

## 24.10

### PROTECTION OF TRANSMISSION LINES AND FEEDERS

The recommendations in Table 24.8 cover overhead transmission lines and cable circuits. A wide range of schemes is possible, as is evident from the number of relay types, so that only general guidance is practicable; considerable scope still exists for adapting schemes to individual requirements. The suggestions in this table form a basis for the selection of suitable equipment.

For the most important circuits, two 'main' protections, either of unit type or distance protection, are frequently used, unrestricted overcurrent and earth fault protection being either discarded or reduced to a subsidiary role. Such combinations are not shown in the table, but can be built up from combinations of schemes 2, 3, 4 and 5.

| Protective system         | Section references | Power system neutral |   |   |   |   |   |           |   |   |   |   |   | Relay type                                                                                         |                                                                      |
|---------------------------|--------------------|----------------------|---|---|---|---|---|-----------|---|---|---|---|---|----------------------------------------------------------------------------------------------------|----------------------------------------------------------------------|
|                           |                    | Earthed              |   |   |   |   |   | Insulated |   |   |   |   |   | Drawout relay                                                                                      | MIDOS relay                                                          |
|                           |                    | Schemes              |   |   |   |   |   | Schemes   |   |   |   |   |   |                                                                                                    |                                                                      |
|                           |                    | 1                    | 2 | 3 | 4 | 5 | 6 | 1         | 2 | 3 | 4 | 5 | 6 |                                                                                                    |                                                                      |
| Time delayed overcurrent  | 9.3                | O                    | X | X | X | - | - | O         | X | X | X | - | - | CDG31, CDG33, CDG34, CDD21, CDD23, CDD24                                                           | MCGG52, 62 or 82<br>MCGG53 or 63<br>METI31 +<br>MCGG52, 53, 62 or 63 |
| Time delayed earth fault  | 9.16               | O                    | X | X | X | - | - | -         | - | - | - | - | - | CDG11, CDG13, CDG14, CDD21, CDD23, CDD24                                                           | MCGG22<br>MCGG22 +<br>METI11 or<br>METI12                            |
| Sensitive earth fault     | 9.16.4             | -                    | Y | - | - | - | - | -         | - | - | - | - | - | CTU15                                                                                              | MCSU                                                                 |
|                           |                    | -                    | - | - | - | - | - | -         | Y | - | - | - | - | NSS4                                                                                               | -                                                                    |
| Distance                  | 11, 12             | -                    | O | - | - | O | O | -         | O | - | - | X | X | See Table 24.9                                                                                     | -                                                                    |
| Longitudinal differential | 10                 | -                    | - | O | - | O | - | -         | - | O | - | X | - | HO4, HOC4, HOA4, HT4, HHTA4, HHTB4, HM4, HMB4, HOR4, DSB7, DS7, DSF7, DSC7, DSC8, Translay S (SDP) | MHOR<br>Translay S (MBCI, MCRI, MRTP, MVTW)                          |
|                           | 13.2.5             | -                    | - | O | - | O | - | -         | - | O | - | X | - | -                                                                                                  | LFCB                                                                 |
| Phase comparison          | 10.11              | -                    | - | - | O | - | O | -         | - | - | O | - | X | Modular relay Type P10                                                                             | -                                                                    |

O General application  
X Where required  
Y Where applicable

Table 24.8 Protection of transmission lines and feeders

## 24.10.1

### Carrier distance protection

All the schemes listed in Table 24.9, are suitable for co-ordination with carrier equipment in carrier distance protection schemes.

The schemes normally supplied are as follows:

- i. Blocking
- ii. Permissive under-reach
- iii. Permissive over-reach
- iv. Zone 2 acceleration

| Type   | Scheme                                                                                  | Basic Units                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
|--------|-----------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| MM1T   | Single zone phase and earth fault protection using one YTG33 relay.                     | Three units for phase fault measurement.<br>Three units for earth fault measurement.<br>All units either mho or offset mho.<br>Used for transformer feeder protection.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| M3T    | Three-zone phase fault or earth fault protection using one YTG31 relay.                 | Three mho units for phase or earth fault measurement.<br>Three offset mho starting units.<br>Used for the protection of high voltage transmission lines.<br>Can be used either for phase or for earth fault protection.<br>Reach of mho units is extended from Zone 1 to Zone 2 by a range change relay after Zone 2 time.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| MM3T   | Three-zone phase and earth fault protection using two YTG31 relays.                     | Three mho units for phase fault measurement.<br>Three offset mho starting units for phase faults.<br>Three mho units for earth fault measurement.<br>Three offset mho starting units for earth faults.<br>Used for phase and earth fault protection of high voltage transmission lines.<br>Reach of mho unit is extended from Zone 1 to Zone 2 by a range change relay after Zone 2 time.<br>Can be used with a signalling channel for high speed fault clearance over the whole line length.                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| SSMM3T | Switched three-zone or four-zone phase and earth fault protection using one PYTS relay. | One fully cross polarized mho unit for phase and earth fault protection of overhead transmission and distribution lines.<br>Special version (PYTC) for underground cables.<br>Instantaneous starting units which may be either: <ol style="list-style-type: none"> <li>a) Three under-impedance units or</li> <li>b) Three overcurrent units or</li> <li>c) Three overcurrent and three undervoltage units.</li> </ol>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| SHPM   | Three-zone phase and earth fault protection using one QUADRAMHO relay.                  | Three shaped mho units for Zone 1 phase fault measurement.<br>Three shaped mho units for Zone 2 phase fault measurement.<br>Three offset mho or offset lenticular units for Zone 3 phase fault measurement.<br>Three quadrilateral or shaped mho units for Zone 1 earth fault measurement.<br>Three quadrilateral or shaped mho units for Zone 2 earth fault measurement.<br>Three offset quadrilateral or offset mho units for Zone 3 earth fault measurement.<br>Used for phase and earth fault protection of transmission and distribution lines.<br>Built-in scheme logic for basic three-step distance, permissive under-reach, permissive over-reach, blocking, and Zone 1 extension schemes. Each scheme has choice of single pole or three pole tripping.<br>Built-in power swing blocking, voltage transformer supervision and self-testing features.<br>Optional directional earth fault protection for high resistance faults can be added as an extra subrack. |
| SHNB   | Three-zone phase and earth fault protection using one MICROMHO relay.                   | Six shaped mho units for Zone 1 measurement.<br>Six shaped mho units for Zone 2 measurement.<br>Six offset mho or offset lenticular units for Zone 3 measurement.<br>Used for ultra-high-speed phase and earth fault protection of EHV and HV transmission lines.<br>Built-in scheme logic for basic three-step distance, permissive under-reach, permissive over-reach, blocking, and Zone 1 extension schemes. Each scheme has choice of single pole or three pole tripping.<br>Built-in self-monitoring.<br>Optional built-in directional earth fault protection for high resistance faults, with basic, permissive over-reach, and blocking schemes.<br>Optional built-in power swing blocking, voltage transformer supervision and mutual compensation features.                                                                                                                                                                                                      |

Table 24.9 Standard distance schemes

#### 24.11 TRANSFORMER-FEEDER PROTECTION

The recommendations in Table 24.10 cover transformer feeders, but not auto-transformer feeders. For the latter type, linking EHV transmission systems, it is usual to protect the auto-transformer and feeder separately (see Tables 24.5 and 24.8) with the addition of intertripping. Oil-immersed transformers of more than 1 MVA are usually fitted with Buchholz protection in addition to the electrically operated protection.

If power can flow in either direction, it is essential that protection against internal faults effect complete isolation of the transformer feeder.

Intertripping is required in association with the following protective systems:

- i. Buchholz
- ii. Winding temperature
- iii. Restricted earth fault
- iv. Separate longitudinal differential protection over the power transformer.

| Protective system                                    | Section reference | Winding and/or power system neutral |   |   |           |   |   | Relay Type                   |                                                                                                          |
|------------------------------------------------------|-------------------|-------------------------------------|---|---|-----------|---|---|------------------------------|----------------------------------------------------------------------------------------------------------|
|                                                      |                   | Earthed                             |   |   | Insulated |   |   | Drawout relay                | MIDOS relay                                                                                              |
|                                                      |                   | Schemes                             |   |   | Schemes   |   |   |                              |                                                                                                          |
|                                                      |                   | 1                                   | 2 | 3 | 1         | 2 | 3 |                              |                                                                                                          |
| Time delayed overcurrent/overcurrent and earth fault | 16.14             | 0                                   | 0 | 0 | 0         | 0 | 0 | CDG31, CDG21<br>CDD21        | MCGG22, MCGG52, MCGG53, MCGG62, MCGG63, MCGG82<br>METI31 + MCGG52, 53, 62 or 63<br>METI11 or 12 + MCGG22 |
| Instantaneous high set overcurrent                   | 16.14             | 0                                   | - | - | 0         | - | - | CAG37, CAG27<br>CAG33, CAG23 | MCAG37, MCAG17<br>MCAG33, MCAG13                                                                         |
| Time delayed earth fault                             | 9.16              | X                                   | X | X | -         | - | - | CDG11, CDD21                 | MCGG22<br>MCGG22 + METI11, MCGG22 + METI12                                                               |
| Instantaneous restricted earth fault                 | 16.6              | 0                                   | 0 | 0 | -         | - | - | FAC14<br>CAG14               | MFAC14<br>MCAG14                                                                                         |
| Neutral displacement                                 | 16.15.1           | X                                   | - | X | 0         | 0 | 0 | VDG12<br>VMU21               | MVTD13<br>MVTU13                                                                                         |
| Longitudinal differential                            | 16.14             | -                                   | 0 | - | -         | 0 | - | HHTA4                        | Translay S (with magnetizing inrush blocking relay MCTH01 if overall scheme)                             |
| Distance                                             | 16.14.1           | -                                   | - | 0 | -         | - | 0 | See Table 24.9               | -                                                                                                        |
| Intertripping                                        | 16.15<br>18.2     | 0                                   | X | 0 | 0         | X | 0 | DBM4<br>DBS4<br>DBSA4        | Translay S (with magnetizing inrush blocking relay MCTH01 if overall scheme)                             |
| O General applications<br>X Where required           |                   |                                     |   |   |           |   |   |                              |                                                                                                          |

0 General applications  
X Where required

Table 24.10 Transformer-feeder protection (excluding auto-transformer feeders)

## 24.12

The recommendations in Table 24.11 cover various types of reactor.

It is usual practice to apply gas-operated (Buchholz) protection in addition to the electric protection specified to oil immersed reactors with a full-load rating of 2 MVA and above.

The ratings of reactors to which thermal devices are applicable are specified in BS 171.

If power can flow in either direction it is essential that protection intended to cover internal faults effect isolation of the reactor.

Overcurrent protection used in conjunction with differential protection provides a back-up function to the latter and also covers uncleared through faults and overloads. It may be needed at only one end of the reactor zone.

Earth fault protection applied to a shunt reactor with earthed neutral point will need to be restricted by the addition of a current transformer in the neutral/earth connection.

| Type of reactor | Protective system                    | Power system neutral |   |           |   | Relay type     |                  |
|-----------------|--------------------------------------|----------------------|---|-----------|---|----------------|------------------|
|                 |                                      | Earthed              |   | Insulated |   | Drawout relay  | MIDOS relay      |
|                 |                                      | Schemes              |   | Schemes   |   |                |                  |
|                 |                                      | 1                    | 2 | 1         | 2 |                |                  |
| Series          | Differential                         | —                    | O | —         | O | FAC34<br>CAG34 | MFAC34<br>MCAG34 |
|                 | Time delayed overcurrent             | O                    | O | O         | O | CDG31          | MCGG62           |
|                 | Time delayed earth fault             | O                    | X | —         | — | CDG11          | MCGG22           |
| Tie-bar         | Differential                         | O                    |   | O         |   | FAC34<br>CAG34 | MFAC34<br>MCAG34 |
|                 | Time delayed overcurrent             | O                    |   | O         |   | CDG31          | MCGG62           |
| Split (duplex)  | Differential                         | O                    |   | O         |   | FAC34<br>CAG34 | MFAC34<br>MCAG34 |
|                 | Time delayed overcurrent             | O                    |   | O         |   | CDG31          | MCGG62           |
|                 | Time delayed overcurrent             | O                    |   | O         |   | CDG31          | MCGG62           |
| Shunt           | Instantaneous restricted earth fault | O                    |   | —         |   | FAC14<br>CAG14 | MFAC14<br>MCAG14 |

O General applications  
X Where required

Table 24.11 Reactor Protection

## 24.13

### INDUCTION MOTOR PROTECTION

The recommendations in Table 24.12 cover important induction motors supplied through circuit breakers.

For motors controlled by starting equipment in line with BS 587, protection is usually provided in the starter, and separate relays are not provided.

Typical starters may include short circuit, earth fault and thermal type overload protection.

When specifying protection, consideration should be given to the cost and functional importance of the motor.

Overload protection has a characteristic inversely proportional to the square of the current, matching the heating curve to the motor. The characteristic must be chosen so that the motor can at least be started normally without tripping.

Short circuit protection can be incorporated in the form of high set elements. Instantaneous earth fault protection can also be included, and should be applied if the power system neutral is earthed.

Reactors or auto-transformers used for motor starting are generally included in the zone of protection.

Motors of 1000 h.p. and above should be provided with differential protection.

If differential protection is not applied, high set instantaneous overcurrent relays should be provided to cover terminal short circuits.

A rotor short circuit on a wound rotor machine might cause excessive starting current; an instantaneous relay set to three or four times normal full load current can be used to detect and trip this condition.

Phase unbalance protection should be applied to all large induction motors. The thermal characteristic of the type MCHN relay is based on the measurement of this current unbalance between phases; it is designed to match the withstand characteristic of the motor.

| Protective system                          | Section reference      | Power system neutral |           | Relay type     |                  |
|--------------------------------------------|------------------------|----------------------|-----------|----------------|------------------|
|                                            |                        | Earthed              | Insulated | Drawout relay  | MIDOS relay      |
| Differential                               | 17.5.1                 | O                    | —         | CAG34<br>FAC34 | MCAG34<br>MFAC34 |
| Inverse time overload                      | 20.4<br>20.15          | O                    | O         | —              | MCHG<br>MCHN     |
| Instantaneous high set overcurrent         | 20.14.4<br>20.15       | X                    | O         | —              | MCHN             |
| Instantaneous earth fault                  | 20.14.1                | X                    | —         | —              | MCHG<br>MCHN     |
| Phase unbalance                            | 20.7<br>20.13<br>20.15 | X                    | X         | —              | MCHG<br>MCHN     |
| Reverse phase sequence and undervoltage    | 19.10                  | X                    | X         | VDM            | —                |
| O General applications<br>X Where required |                        |                      |           |                |                  |

Table 24.12 Protection of induction motors controlled by circuit breakers, not starters

The recommendations in Table 24.13 represent the protective requirements of synchronous motors and compensators, including ancillary equipment such as reactors and auto-transformers.

The response of protective systems to internal faults should effect complete isolation of the plant by tripping both the main and the field circuit breakers.

Underpower and reverse power protection is required to prevent a restoration of supply following an interruption, with the machine out of synchronism with the system. A zero power setting, corresponding to a normally closed contact, is required if the machine may be isolated with no parallel load into which to feed back. Interlocking with the starting circuits will be necessary. A slight definite time delay (about 2 s) should be applied to prevent tripping from power swings.

Overvoltage protection will operate on loss of supply if the motor is over-excited.

Underfrequency protection will respond to the falling frequency on loss of supply in the case of a motor driving a low inertia load such as a compressor which will cause the motor speed to fall quickly.

Rotor earth fault protection is normally applied to large machines (those rated at 10 MVA and above) and may only give an alarm.

| Protective system                         | Section reference | 50 to 1000 h.p. | Above 1000 h.p. | Relay type     |                  |
|-------------------------------------------|-------------------|-----------------|-----------------|----------------|------------------|
|                                           |                   |                 |                 | Drawout relay  | MIDOS relay      |
| Differential                              | 17.5.1            | —               | O               | CAG34<br>FAC34 | MCAG34<br>MFAC34 |
| Thermal overload                          | 20.4              | O               | O               | —              | MCHG<br>MCHN     |
| Instantaneous high set overcurrent        | 20.14.4<br>20.15  | O               | —               | —              | MCHN             |
| Instantaneous earth fault                 | 20.14.1           | O               | X               | —              | MCHG<br>MCHN     |
| Phase unbalance                           | 20.7<br>20.13     | O               | O               | —              | MCHG<br>MCHN     |
| Under and reverse power                   | 20.17.5           | X               | X               | WCD12          | —                |
| Overvoltage                               | 20.17.6           | —               | X               | VDG11          | MVTD12           |
| Field failure                             | 17.13             | —               | X               | DBA4           | —                |
| Rotor earth fault                         | 17.12.1           | —               | X               | VME<br>DBAE    | MRSU             |
| Underfrequency                            | 20.17.6           | —               | X               | FMG12          | MFVU             |
| O General application<br>X Where required |                   |                 |                 |                |                  |

Table 24.13 Protection of synchronous motors and compensators

## RECTIFIER PROTECTION

The recommendations in Table 24.14 cover rectifiers and their associated transformers. Fuses are used on small equipment where the use of circuit breakers is not justified. If the transformer has a low reactance, instantaneous overcurrent protection is high set and an inverse time delayed relay may be used to supplement it. Conversely, when the transformer has a high reactance, instantaneous protection is set lower and time delayed overcurrent protection is sometimes omitted.

Restricted earth fault protection covers the primary winding of the supply transformer.

Reverse current protection is applied to the d.c. circuit when feedback to an internal short circuit arc (back-fire) may occur.

| Protective system                          |      | Section reference | Classes 1 and 2<br>Industrial and light traction service |      | Classes 3 and 4<br>Railway traction service        |      | Class 5<br>Electrochemical service                 |      | EHV D.C. service with arc suppression | Relay type      |                  |
|--------------------------------------------|------|-------------------|----------------------------------------------------------|------|----------------------------------------------------|------|----------------------------------------------------|------|---------------------------------------|-----------------|------------------|
|                                            |      |                   | Anode fuses or circuit breakers                          |      | Anode fuses or circuit breakers or arc suppression |      | Anode fuses or circuit breakers or arc suppression |      |                                       | Drawout relay   | MIDOS relay      |
|                                            |      |                   | Included                                                 | None | Included                                           | None | Included                                           | None |                                       |                 |                  |
| Time delayed overcurrent                   | A.C. | 21.3<br>21.4.4    | O                                                        | X    | O                                                  | X    | O                                                  | X    | O                                     | CDG33<br>CTG25E | MC3362<br>MCTD01 |
| Instantaneous overcurrent                  | A.C. | 21.3<br>21.4.4    | —                                                        | O    | —                                                  | O    | —                                                  | O    | —                                     | CAG3E<br>CAG31  | MCAG39<br>MCAG31 |
| Instantaneous restricted earth fault       | A.C. | 21.3<br>21.4.4    | O                                                        | O    | O                                                  | O    | O                                                  | O    | O                                     | CAG14<br>FAC14  | MCAG14<br>MFAC14 |
| Reverse current                            | D.C. | 21.3              | X                                                        | X    | O                                                  | O    | X                                                  | X    | X                                     | OM3             | —                |
| O General applications<br>X Where required |      |                   |                                                          |      |                                                    |      |                                                    |      |                                       |                 |                  |

Table 24.14 Rectifier protection



Well over 100 different auto-reclose schemes have been produced by GEC ALSTHOM Measurements. Some are standard schemes, designed for common auto-reclose applications, but many relays have been designed to meet

the special requirements of individual customers.

Some of the early schemes have been technically superseded by relays employing static circuits or microprocessor technology for greater flexibility in meeting similar basic requirements, but many of the older schemes can still be supplied. Some electromechanical relays are included in

| Relay type | Group | Dead time                                                          | Reclaim time                                                              | Duration of closing pulse                  | Remarks                                                                                                                                                                                                                                                                                                                                     |
|------------|-------|--------------------------------------------------------------------|---------------------------------------------------------------------------|--------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| VAR22A     | A     | Within 2–10 s, 5–25 s, 10–60 s or 20–120 s subject to reclaim time | Up to the maximum time of range, less dead time setting (passing contact) | Approximately 10% of maximum timer setting | For use on radial feeders with I.D.M.T. protection.                                                                                                                                                                                                                                                                                         |
| VAR28A     | B     | 0.1–1 s, 0.2–2 s, 0.5–5 s, 1–10 s, 2–20 s, 5–50 s or 10–100 sM     | 5–50 s or 10–100 s                                                        | Cancelled by circuit breaker               | For use on radial feeders with I.D.M.T. and low set instantaneous overcurrent protection. CB trip by instantaneous protection inhibited after first trip.                                                                                                                                                                                   |
| VAR28B     | B     | 0.1–1 s, 0.2–2 s, 0.5–5 s, 1–10 s, 2–20 s, 5–50 s or 10–100 s      | Fixed at specified value between 20 s to 240 s                            | Cancelled by circuit breaker               | Suitable for BEBNC Scheme R7 when used with VAR18A counter.                                                                                                                                                                                                                                                                                 |
| VAR39A     | A     | 5–60 s                                                             | Equals CB spring winding time                                             | Cancelled by circuit breaker               | BEBNC Scheme R2, for use with motor-wound spring CB's.                                                                                                                                                                                                                                                                                      |
| VAR39B     | A     | 0.5–35 s                                                           | Equals CB spring winding time                                             | Cancelled by circuit breaker               | Includes maintenance counter to lock-out auto-reclosure after 1–19 fault trips.                                                                                                                                                                                                                                                             |
| VAR41N     | A     | 0.06–0.6 s, 0.1–1.0 s, or 0.5–3.0 s                                | 5–25 s, 10–60 s, or 20–120 s                                              | Cancelled by circuit breaker               | For high speed auto-reclosing on HV transmission lines protected by high speed distance or pilot wire protection. Optional pre-closing check.                                                                                                                                                                                               |
| VAR49A     | A     | Within 5–60 s subject to reclaim time                              | Up to the maximum time of range, less dead time setting (passing contact) | Approximately 1 or 2 s                     | BEBNC Scheme R3 for use with spring or solenoid operated CB's.                                                                                                                                                                                                                                                                              |
| VAR49C     | A     | Within 0.5–1.5 s or 5–35 s subject to reclaim time                 | Up to the maximum time of range, less dead time setting (passing contact) | 1 s                                        | Includes maintenance counter to lock out auto-reclosure after 1–19 trips.                                                                                                                                                                                                                                                                   |
| VAR68A     | B     | 0.1–1 s, 0.2–2 s, 0.5–5 s, 1–10 s, 2–20 s, 5–50 s or 10–100 s      | 5–50 s or 10–100 s                                                        | Cancelled by circuit breaker               | For high speed auto-reclosing on HV transmission lines protected by high speed distance or pilot wire protection. Optional pre-closing check.                                                                                                                                                                                               |
| VAR79A     | A     | Within 5–60 s subject to reclaim time                              | Up to the maximum time of range, less dead time setting (passing contact) | Approximately 1 or 2 s                     | BEBNC Scheme R4, for use with spring or solenoid operated CB's.                                                                                                                                                                                                                                                                             |
| VAR79D     | A     | Within 0.5–1.5 s or 5–35 s subject to reclaim time                 | Up to the maximum time of range less dead time setting (passing contact)  | 1 s                                        | Maintenance counter gives pre-lockout alarm after 1–19 fault trips, then final lockout after one more auto-reclose and fault trip.                                                                                                                                                                                                          |
| MVTR01     | B     | 0.1–99.9 s                                                         | 1–999 s                                                                   | Cancelled by circuit breaker               | High-speed or delayed auto-reclosure for HV transmission lines protected by high speed distance or pilot wire protection.<br>Also for radial feeders with I.D.M.T. and low set instantaneous overcurrent protection.<br>CB trip by non-discriminating protection can be inhibited after first trip. Optional pre-closing check and counter. |
| MVTR02     | B     | 0.1–99.9 s                                                         | 1–999 s                                                                   | Cancelled by circuit breaker               | As MVTR01 except lockout element resets automatically when CB closes.                                                                                                                                                                                                                                                                       |

Table 24.15 Single shot, three phase auto-reclose relays

the following tables, which list the principal relays currently available for common auto-reclose applications and their nominal characteristics. All the auto-reclose schemes listed in the tables are initiated by the operation of a protective relay. Other schemes are available, on request, for special applications.

The basic relay groups, identified by letters A, B or C in the tables are:

**A.** Schemes employing electromechanical relay contact logic for sequence control, and electromechanical (VAT type) timers.

**B.** Schemes employing contact logic for sequence control, and static circuitry (R-C or VTT type circuits) for timing functions.

**C.** Schemes employing microprocessor technology both for sequence control and timing functions.

| Relay type | Group | Number of shots | Dead time                                                                                                               | Reclaim time                                                                                                                    | Duration of closing pulse                                            | Remarks                                                                                                                                                                                                                                                             |
|------------|-------|-----------------|-------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| VAR48A     | B     | 1 to 3          | Selectable for each reclosure (shot) from 0.1–1 s, 0.2–2 s, 0.5–5 s, 1–10 s, 2–20 s, 5–50 s, or 10–100 s                | Selectable from 0.1–1 s, 0.2–2 s, 0.5–5 s, 1–10 s, 2–20 s, 5–50 s, or 10–100 s. (same reclaim time after each reclose attempt). | Cancelled by circuit breaker                                         | Adjustable for up to 3 shot reclose cycle. For use on radial feeders with I.D.M.T. and low set instantaneous overcurrent protection. Optional instantaneous protection inhibit after first or second trip. Can be used with counter VAR18A to form BEBNC Scheme R8. |
| VAR48D     | B     | 1 to 4          | As VAR48A                                                                                                               | As VAR48A                                                                                                                       | Cancelled by circuit breaker                                         | As VAR48A                                                                                                                                                                                                                                                           |
| VAR55C     | A     | 1 to 4          | Single timer with four independently adjustable 'passing' contact operations and 'final' contact. Overall range 0–60 s. | 10 s after final operation of passing contact                                                                                   | Cancelled by circuit breaker                                         | Application as VAR48, but CB trip by instantaneous protection inhibited after first trip (not adjustable).                                                                                                                                                          |
| MVTR51     | C     | 1 to 4          | Trip: Range 1 0.2–200 s<br>2–4 1–200 s each                                                                             | 1–200 s                                                                                                                         | Cancelled by circuit breaker or maintained for 0.1–2 s (selectable). | Application as VAR48, but CB trip by instantaneous protection may be inhibited after any selected trip in reclose cycle. A versatile microprocessor-based scheme with extensive user options selected by keypad. Settings displayed on LCD.                         |
| MVTR52     | C     | 1 to 4          | As MVTR51                                                                                                               | As MVTR51                                                                                                                       | As MVTR51                                                            | As MVTR51, plus versatile user-adjustable maintenance alarm and lockout counter, and 'excessive fault frequency' lockout.                                                                                                                                           |

Table 24.16 Multi-shot, three phase auto-reclose relays.

| Relay type | Group | Dead time                                                                                               | Reclaim time       | Duration of closing pulse                                           | Remarks                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
|------------|-------|---------------------------------------------------------------------------------------------------------|--------------------|---------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| VAR88B     | B     | 1 Phase : 0.1–1 s or 0.2–2 s<br>3 Phase : 0.1–1 s, 0.2–2 s, 0.5–5 s, 1–10 s, 2–20 s, 5–50 s or 10–100 s | 5–50 s or 10–100 s | 0.5 s (0.2–2.4 s to order)<br>cancelled by persistent fault         | Selectable to any one of four cycles:<br>i. 1 Phase reclose for 1 phase faults (single shot) 3 phase trip and lockout for multi-phase faults.<br>ii. 3 Phase trip and reclose for any fault (single shot).<br>iii. 1 Phase reclose for 1 phase faults (single shot) 3 phase trip and reclose for multi-phase faults (single shot).<br>iv. 1 Phase reclose followed by 3 phase trip and reclose for non-transient 1 phase faults (two shot).<br>3 phase trip and reclose for multi-phase faults (single shot).<br>Optional pre-closing check (SKD, VAR113 or MAVS relay extra). |
| MVTR53     | C     | 1 Phase: 0–200 s<br>3 Phase: 0–300 s<br>Delayed second shot : 2–300 s                                   | 2–300 s            | Cancelled by circuit breaker or maintained for 0.1–2 s (selectable) | Single breaker applications; second shot optional.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |

Table 24.17 Single/three phase auto-reclose relays.

### 24.16.1

#### Special auto-reclose schemes for complex substations

Composite schemes incorporating electromechanical relays types VAR82, VAR101-112 and VAR114-117 have been developed to meet the special auto-switching requirements of densely interconnected networks with complex substation arrangements, such as mesh-type substations with feeder/banked transformer circuits at each mesh corner.

Microprocessor-based PERM equipment packages have also been developed for these applications.

The requirements and facilities of the more complex applications are considered individually and vary in many ways as a result. It is therefore not practical to summarize them in the simple tabular form shown for individual auto-reclosing relays.

### 24.16.2

#### Ancillary relays for use with auto-reclose schemes

|        |                                                                                                                                                                         |
|--------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| SKD    | Synchronism check relay.                                                                                                                                                |
| VAR113 | Voltage monitor relay. Two elements monitor line and bus VT's, and give permissive close output for dead line charge or dead bus charge conditions.                     |
| MAVS   | MIDOS synchronism check/voltage monitor relay, combining the functions of the SKD and VAR113.                                                                           |
| VAR18A | Counting relay for use with VAR28 or 48 relays. Gives alarm after 1-99 fault trips or A/R attempts followed by 'lockout' after further 1-9 fault trips or A/R attempts. |
| MVTC   | MIDOS counting relay for use with MVTR01/02. Function similar to VAR18A.                                                                                                |

### 24.17

#### SUMMARY OF INDIVIDUAL RELAYS

This section gives a summary of the wide range of standard protective relays and signalling equipment that is available for the protection of electrical plant and power system networks. The list of relays is arranged in alphabetical order for ease of reference and includes all the basic designs: hinged armature, moving coil, induction disc, induction cup, polarized and static.

|       |                                                                                                                                                         |
|-------|---------------------------------------------------------------------------------------------------------------------------------------------------------|
| CAA   | Series overcurrent auxiliary relay.                                                                                                                     |
| CAEF  | Earth fault indicator.                                                                                                                                  |
| CAF11 | Series flag indicator relay.                                                                                                                            |
| CAG11 | Instantaneous overcurrent relay with fixed setting.                                                                                                     |
| CAG12 | Instantaneous overcurrent relay with variable settings and low drop-off/pick-up ratio.                                                                  |
| CAG13 | High set instantaneous overcurrent relay with variable settings and high transient over-reach.                                                          |
| CAG14 | High impedance differential relay with variable current settings.                                                                                       |
| CAG17 | High set instantaneous overcurrent relay with variable settings and high drop-off/pick-up ratio. Low transient over-reach.                              |
| CAG19 | Instantaneous overcurrent relay with variable settings and high drop-off/pick-up ratio. Low transient over-reach.                                       |
| CD4   | Battery negative biasing relay.                                                                                                                         |
| CDAG  | Overcurrent relay with time delayed phase fault elements having any of the standard inverse characteristics, plus an instantaneous earth fault element. |
| CDD21 | Directional inverse time overcurrent relay with a single contact on the disc.                                                                           |

|        |                                                                                                                   |
|--------|-------------------------------------------------------------------------------------------------------------------|
| CDD23  | Directional very inverse time overcurrent relay.                                                                  |
| CDD24  | Directional extremely inverse time overcurrent relay.                                                             |
| CDD26  | Directional inverse time overcurrent relay with two contacts on the disc.                                         |
| CDG11  | Inverse time overcurrent relay with basic inverse time operating characteristic and a single contact on the disc. |
| CDG12  | Inverse time overcurrent relay with long time operating characteristic.                                           |
| CDG13  | Very inverse time overcurrent relay.                                                                              |
| CDG14  | Extremely inverse time overcurrent relay.                                                                         |
| CDG16  | Inverse time overcurrent relay with basic inverse time operating characteristic and two contacts on the disc.     |
| CDV21  | Voltage restrained inverse time overcurrent relay.                                                                |
| CDV22  | Voltage controlled inverse time overcurrent relay.                                                                |
| CETS   | Automatic sectionalizer for overhead distribution lines.                                                          |
| CME    | Battery earth fault relay.                                                                                        |
| CTIG39 | Local breaker back-up relay with one instantaneous overcurrent element per phase.                                 |
| CTIG68 | Local breaker back-up relay with two instantaneous overcurrent elements per phase.                                |
| CTN    | Negative phase sequence relay with inverse time characteristic for generator protection. Static.                  |
| CTS    | Motor stalling relay.                                                                                             |
| CTU15  | Static sensitive earth fault relay. Definite time characteristic.                                                 |
| CTZ    | Static overcurrent trip device for LV circuit breakers.                                                           |
| DBA4   | Moving coil relay with variable settings and a single adjustable setting.                                         |
| DBAE4  | Rotor earth fault relay.                                                                                          |
| DBB4   | Moving coil relay with variable settings and two adjustable settings.                                             |
| DBM4   | Surge-proof intertrip receive relay. Shunt connection.                                                            |
| DBS4   | Surge-proof intertrip receive relay with low impedance for series connection.                                     |
| DBSA4  | Surge-proof intertrip receive relay with low impedance for series connection and higher surge withstand.          |
| DDG31  | Generator percentage biased differential relay.                                                                   |
| DDGT31 | Generator-transformer percentage biased differential relay.                                                       |
| DDT32  | Transformer percentage biased differential relay.                                                                 |
| DSC8   | Plain feeder high speed pilot wire relay. Post Office pilots.                                                     |
| DTH    | Static transformer percentage biased differential relay with harmonic restraint.                                  |
| DVM4   | Voltage transformer supply supervision relay.                                                                     |
| FAC14  | High impedance voltage calibrated differential relay with variable settings.                                      |
| FMG11  | Overfrequency relay.                                                                                              |
| FMG12  | Underfrequency relay.                                                                                             |
| FOS24  | Synchronous motor out-of-step relay.                                                                              |
| FTG11  | Static underfrequency relay.                                                                                      |
| GTT    | Overfluxing relay.                                                                                                |
| HHTA4  | Translay transformer feeder medium speed pilot wire relay.                                                        |
| HHTB4  | Translay tee'd transformer feeder medium speed pilot wire relay.                                                  |
| HM4    | Translay plain feeder medium speed pilot wire relay. Without overcurrent starting relays. Post Office pilots.     |
| HMB4   | Translay plain feeder medium speed pilot wire relay. With overcurrent starting relays. Post Office pilots.        |



|        |                                                                                                                            |        |                                                                                                                      |
|--------|----------------------------------------------------------------------------------------------------------------------------|--------|----------------------------------------------------------------------------------------------------------------------|
| MCAA   | Tripping and auxiliary attracted armature, all-or-nothing, overcurrent relays.                                             | MFVU   | Digital, independent time under or overfrequency relay.                                                              |
| MCAG11 | Instantaneous attracted armature overcurrent measuring relay. Single element, fixed setting.                               | MHOR   | Pilot wire feeder protection, equivalent to and compatible with, Reyrolle's 'Solkor R' protection.                   |
| MCAG12 | Instantaneous overcurrent relay. Single element, seven tapped settings.                                                    | MRSU   | Rotor earth fault protection relay, using a.c. injection.                                                            |
| MCAG13 | Instantaneous overcurrent relay. Single element, spring controlled settings.                                               | M RTP  | Pilot wire supervision relay.                                                                                        |
| MCAG14 | Instantaneous overcurrent relay. Single element, tuned, differential.                                                      | MSTZ   | Power supply unit.                                                                                                   |
| MCAG17 | Instantaneous overcurrent relay. Single element, tuned, adjustable settings.                                               | MVAA   | Attracted armature, tripping and auxiliary relay.                                                                    |
| MCAG19 | Instantaneous overcurrent relay. Single element, C.T. fed, adjustable settings.                                            | MVAA16 | High speed attracted armature tripping and auxiliary relay equivalent to special MVAA to obtain 4 ms operation time. |
| MCAG31 | Instantaneous overcurrent relay. Three element, fixed settings.                                                            | MVAG11 | Attracted armature undervoltage relay. 1 element, low DO/PU, single fixed setting.                                   |
| MCAG32 | Instantaneous overcurrent relay. Three element, seven tapped settings.                                                     | MVAG12 | Undervoltage relay, 1 element, high DO/PU, single, fixed setting.                                                    |
| MCAG33 | Instantaneous overcurrent relay. Three element, spring controlled settings.                                                | MVAG13 | Undervoltage relay, 1 element, low DO/PU, range of fixed settings by tappings.                                       |
| MCAG34 | Instantaneous overcurrent relay. Three element, tuned, differential.                                                       | MVAG14 | Undervoltage relay, 1 element, high DO/PU, range of fixed settings by tappings.                                      |
| MCAG37 | Instantaneous overcurrent relay. Three element, tuned, adjustable settings.                                                | MVAG15 | Overvoltage relay, 1 element, low DO/PU, single, fixed setting.                                                      |
| MCAG39 | Instantaneous overcurrent relay. Three element, C.T. fed, adjustable settings.                                             | MVAG16 | Overvoltage relay, 1 element, high DO/PU, single, fixed setting.                                                     |
| MCGG22 | Single phase, time delayed overcurrent relay with high set instantaneous element.                                          | MVAG17 | Overvoltage relay, 1 element, low DO/PU, range of fixed settings by tappings.                                        |
| MCGG42 | Time delayed overcurrent relay with two phase elements.                                                                    | MVAG18 | Overvoltage relay, 1 element, high DO/PU, range of fixed settings by tappings.                                       |
| MCGG52 | Time delayed overcurrent relay with two phase and one earth fault elements, and with high set elements.                    | MVAG21 | Undervoltage or overvoltage dual element low DO/PU relay.                                                            |
| MCGG53 | Time delayed overcurrent relay with two phase (polyphase) element and one earth fault element, and with high set elements. | MVAG22 | Undervoltage or overvoltage dual element high DO/PU relay.                                                           |
| MCGG62 | Time delayed overcurrent relay with three phase fault elements, and with high set elements.                                | MVAG31 | Undervoltage relay, 3 elements, low DO/PU, single, fixed settings.                                                   |
| MCGG63 | Three phase (polyphase) time delayed overcurrent relay with high set element.                                              | MVAG32 | Undervoltage relay, 3 elements, high DO/PU, single, fixed settings.                                                  |
| MCGG82 | Time delayed overcurrent relay with three phase and one earth fault elements, and with high set elements.                  | MVAG33 | Undervoltage relay, 3 elements, low DO/PU, range of fixed settings by tappings.                                      |
| MCHD   | Thermal overload relay with $I^2t$ characteristic, plus high set independent time overcurrent element.                     | MVAG34 | Undervoltage relay, 3 elements, high DO/PU, range of fixed settings by tappings.                                     |
| MCHG   | Motor protection relay.                                                                                                    | MVAG35 | Overvoltage relay, 3 elements, low DO/PU, single, fixed settings.                                                    |
| MCHN   | Motor protection relay with thermal characteristic derived from sequence component currents.                               | MVAG36 | Overvoltage relay, 3 elements, high DO/PU, single, fixed settings.                                                   |
| MCND   | Static negative phase sequence overcurrent relay.                                                                          | MVAG37 | Overvoltage relay, 3 elements, low DO/PU, range of fixed settings by tappings.                                       |
| MCRI   | Vibrating reed, overvoltage check/starting relay. For use with Translay 'S' protection.                                    | MVAG38 | Overvoltage relay, 3 elements, high DO/PU, range of fixed settings by tappings.                                      |
| MCSU   | Sensitive earth fault relay.                                                                                               | MVAJ11 | High security, attracted armature tripping and control relay. Self reset/economy.                                    |
| MCTD   | Dependent time overcurrent relay, for rectifier protection.                                                                | MVAJ13 | Tripping and control relay. Hand reset/instantaneous.                                                                |
| MCTH   | Magnetizing inrush blocking relay. For use with Translay 'S' protection on transformer feeders.                            | MVAJ14 | Tripping and control relay. Electrical reset/instantaneous.                                                          |
| MCTI   | Instantaneous overcurrent relays (breaker fail).                                                                           | MVAJ15 | Tripping and control relay. Hand/electrical reset—instantaneous.                                                     |
| MCVG   | Voltage restrained overcurrent relay with dependent time characteristic.                                                   | MVAJ17 | Tripping and control relay. Self reset/economy. (CEGB Specification P15).                                            |
| METI11 | Single phase, voltage polarized, directional relay (for directionalizing MCGG relays).                                     | MVAJ21 | Tripping and control relay. Self reset/economy. (UK Elec. Board Classification EB2).                                 |
| METI12 | Single phase, dual polarized directional relay.                                                                            | MVAJ23 | Tripping and control relay. Hand reset/instantaneous 4/10 contacts.                                                  |
| METI31 | Three phase, voltage polarized directional relay.                                                                          | MVAJ24 | Tripping and control relay. Electrical reset/instantaneous 4/9 contacts.                                             |
| MFAC14 | Attracted armature high impedance differential relay. Single element restricted earth fault.                               | MVAJ25 | Tripping and control relay. Hand/electrical reset/instantaneous.                                                     |
| MFAC34 | Three element, high impedance differential relay for busbar/generator protection.                                          | MVAJ26 | Tripping and control relay. Self reset/time delay, economy.                                                          |
|        |                                                                                                                            | MVAJ27 | Tripping and control relay. Hand reset/time delay.                                                                   |
|        |                                                                                                                            | MVAJ28 | Tripping and control relay. Electrical reset/time delay.                                                             |
|        |                                                                                                                            | MVAJ29 | Tripping and control relay. Hand-electrical reset/time delay.                                                        |

MVAJ34 Tripping and control relay. Electrical reset/instantaneous. (CEGB Transmission Department Memorandum Specification 112).

MVAP Voltage selection relay.

VAW Interposing relay.

MVAX12 Trip supply supervision relay.

IVAX21 Trip supply and trip circuit supervision relay. Breaker closed.

IVAX31 Trip supply and trip circuit supervision relay. Breaker open/closed.

MVGC Voltage regulating relay. With supervision, line drop compensation, load shedding facilities and circulating current compensation.

MVGL01 Logic relay for MIDOS directional earth fault scheme.

MVRF Indication relay.

MVTC Maintenance alarm and lockout relay with counter (for use with auto-reclose relays such as MVTR).

MVTD11 Static undervoltage relay. A.c., dependent time.

MVTD12 Static overvoltage relay. A.c., dependent time.

MVTD13 Static a.c. voltage relay for neutral displacement detection.

MVTI11 Static, instantaneous, a.c. undervoltage relay.

MVTI12 Static, instantaneous, a.c. overvoltage relay.

MVTP11 Single element buswire supervision relay.

MVTP31 Three phase buswire supervision relay.

MVTR01 Static, single shot, 3 phase auto-reclosing relay.

MVTR51 Static, multi-shot auto-reclosing relay.

MVTR52 Static, multi-shot auto-reclosing relay.

MVTT14 Static time delay relay. Delay on pick-up. Setting range 100/1 or 1000/1.

MVTT15 Static time delay relay. Delay on drop-off. Setting range 100/1 or 1000/1.

MVTU11 Static, independent time, a.c. undervoltage relay.

MVTU12 Static, independent time, a.c. overvoltage relay.

MVTU13 Static, independent time, a.c. voltage relay to detect neutral displacement.

MVTW Destabilizing and intertrip relay. (For use with pilot wire relays such as Translay S).

MVUA Voltage relays with relatively short, fixed time delays on operation or resetting.

MWTU01 Independent time overpower/reverse power relay.

MYTU Static impedance relay, with mho characteristic and definite time delay, for field failure detection.

MZTU Under-impedance relay with definite time delay.

#### **MIDOS test equipment**

MMLB01 Multi-finger test plug.

MMLB02 Single finger test plug.

MMLG01 14 way test block.



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